STATE OF FLORIDA
OFFICE OF PUBLIC COUNSEL

C/O THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
SUITE 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

EMAIL: OPC_WEBSITE@LEG.STATE.FL.US
WWW.FLORIDAOPC.GOV

BEN ALBRITTON
President of the Senate

DANIEL PEREZ
Speaker of the House of Representatives

July 24, 2025

Adam J. Teitzman, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Docket No. 20250011-EI - Petition for rate increase by Florida Power & Light Company

Dear Mr. Teitzman:

Please find enclosed for filing in the above referenced docket the Motion and Notice of Intent to Seek Official Recognition. This filing is being made via the Florida Public Service Commission's web-based electronic filing portal in five separate filings due to the voluminous sizes of the Exhibits. They will be identified by Numbers 1-5.

This filing is **No. 1 of 5, which includes**:

- The Motion and Notice of Intent to Seek Official Recognition
- Exhibits A, B, C, D, E, F, G, H, I, K, M, and N.

Please note **Exhibit J has been divided into three parts due to electronic filing requirements.** It will be submitted as follows:

- Filing No. 2 of 5: Exhibit J (Part 1)
- Filing No. 3 of 5: Exhibit J (Part 2)
- Filing No. 4 of 5: Exhibit J (Part 3)
- Filing No. 5 of 5: **Exhibit L**

If you have any questions or concerns, please do not hesitate to contact me. Thank you for your assistance in this matter.

Sincerely,

Walt Trierweiler
Public Counsel

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
Florida Bar No.: 93590
wessling.mary@leg.state.fl.us
#850-488-9330

CERTIFICATE OF SERVICE
DOCKET NO. 20250011-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 24th day of July, 2025, to the following:

Shaw Stiller
Timothy Sparks
Florida Public Service Commission
Office of General Counsel
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
sstiller@psc.state.fl.us
tsparks@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Kenneth A. Hoffman
Florida Power & Light Company
134 West Jefferson Street
Tallahassee, FL 32301-1713
ken.hoffman@fpl.com

John T. Burnett
Maria Moncada
Christopher T. Wright
Joel Baker
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
john.t.burnett@fpl.com
maria.moncada@fpl.com
christopher.wright@fpl.com
joel.baker@fpl.com

Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

Leslie R. Newton
Ashley N. George
Thomas A. Jernigan
Michael A. Rivera
James B. Ely
Ebony M. Payton
Federal Executive Agencies
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403
leslie.newton.1@us.af.mil
ashley.george.4@us.af.mil
thomas.jernigan.3@us.af.mil
michael.rivera.51@us.af.mil
james.ely@us.af.mil
ebony.payton.ctr@us.af.mil

Nikhil Vijaykar
Yonatan Moskowitz
Keyes & Fox LLP
580 California St., 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com
ymoskowitz@keyesfox.com

Katelyn Lee
Lindsey Stegall
EVgo Services, LLC
1661 E. Franklin Ave.
El Segundo, CA 90245
katelyn.lee@evgo.com
lindsey.stegall@evgo.com

Bradley Marshall
Jordan Luebkemann
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, FL 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org
flcaseupdates@earthjustice.org

Danielle McManamon
Bianca Blanshine
Earthjustice
4500 Biscayne Blvd., Suite 201
Miami, FL 33137
dmcmanamon@earthjustice.org
bblanshine@earthjustice.org

James W. Brew
Laura Wynn Baker
Joseph R. Briscar
Sarah B. Newman
Stone Mattheis Xenopoulos & Brew
1025 Thomas Jefferson St., NW
Suite 800 West
Washington, D.C. 20007
jbrew@smxblaw.com
lwb@smxblaw.com
jrb@smxblaw.com
sbn@smxblaw.com

Stephen Bright
Jigar J. Shah
Electrify America, LLC
1950 Opportunity Way, Suite 1500
Reston, Virginia
steve.bright@electrifyamerica.com
jigar.shah@electrifyamerica.com

Stephanie U. Eaton
Spilman Thomas & Battle
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
seaton@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
slee@spilmanlaw.com

William C. Garner
Law Office of William C. Garner
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

D. Bruce May
Kevin W. Cox
Kathryn Isted
Holland & Knight LLP
315 S. Calhoun Street, Suite 600
Tallahassee, FL 32301
bruce.may@hklaw.com
kevin.cox@hklaw.com
kathryn.isted@hklaw.com

Robert Scheffel Wright
John T. LaVia, III
Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

Floyd R. Self
Ruth Vafek
Berger Singerman, LLP
313 N. Monroe Street, Suite 301
Tallahassee, FL 32301
fself@bergersingerman.com
rvafek@bergersingerman.com

Brian A. Ardire
Armstrong World Industries, Inc.
2500 Columbia Avenue
Lancaster, PA 17603
baardire@armstrongceilings.com

Robert E. Montejo
Duane Morris LLP
201 S Biscayne Blvd., Suite 3400
Miami, FL 33131-4325
remontejo@duanemorris.com

Alexander W. Judd
Duane Morris LLP
100 Pearl Street, 13th Floor
Hartford, CT 06103
ajudd@duanemorris.com

/s/ Mary A. Wessling
Mary A. Wessling
Associate Public Counsel
wessling.mary@leg.state.fl.us

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	DOCKET NO. 20250011-EI FILED: July 24, 2025

MOTION AND NOTICE OF INTENT TO SEEK OFFICIAL RECOGNITION

Pursuant to Section 120.569(2)(i), Fla. Stat., Sections 90.201 and 90.202, Fla. Stat., as provided for in Rule 28-106.213(6), Florida Administrative Code ("F.A.C."), and Paragraph VI(h) of Order No. PSC-2025-0075-PCO-EI, the Citizens of the State of Florida, by and through the Office of Public Counsel ("OPC"), respectfully request the Florida Public Service Commission ("Commission") take official recognition of the following:

Pursuant to Section 90.201(1), Florida Statutes:

Exhibit A – "One Big, Beautiful Bill Act" (Public Law 119-21)
Exhibit B – Laws of Florida 2024-186

Pursuant to Section 90.202(2), Florida Statutes:

Exhibit C - Texas Statute SB 6 enacted June 20, 2025

Pursuant to Section 90.202(3), Florida Statutes:

Exhibit D – Executive Order No. 14154 "Unleashing American Energy"
Exhibit E – Executive Order No. 14156 "Declaring a National Energy Emergency"
Exhibit F – Executive Order No. 14315 "Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources"

Pursuant to Section 90.202(5), Florida Statutes:

Exhibit G – United States Treasury Guidance Relating to the "One Big, Beautiful Bill Act" *(Expected to be issued on or about August 18, 2025)*
Exhibit H – Governor DeSantis' veto of Senate Bill 1574

Pursuant to Section 90.202(6), Florida Statutes:

Exhibit I – FPL's Joint Application for Authorization Under Section 203 of Federal Power Act of Vandolah Power Company LLC et al., under EC25-101
Exhibit J – All written customer comments filed in Florida Public Service Commission Docket 20250011-EI through July 16, 2025.
Exhibit K – Public Utilities Commission of Ohio Opinion and Order in Case No. 24-508-EL-ATA
Exhibit L – FPL's 2016-2024 PSC Annual Reports

Pursuant to Section 90.202(11)-(12), Florida Statutes:

Exhibit M – Congressional letter to Secretary Robert F. Kennedy, Jr, Secretary of Health and Human Services, dated April 4, 2025
Exhibit N – "Florida's Top 10 Private Landowners," Florida Trend Magazine, published January 16, 2025

Legal Authority

1) Pursuant to Section 120.57(1)(j), Florida Statutes, "[f]indings of fact….shall be based exclusively on the evidence of record and on matters officially recognized."

2) Pursuant to Section 120.569(2)(i), Florida Statutes, and Rule 28-106.213(6), F.A.C., a party may seek official recognition of matters set forth in Sections 90.201-203, Florida Statutes. Rule 28-106.213(6), F.A.C., also states that "[r]equests for official recognition shall be by motion."

3) Section 90.201(1), Florida Statutes, provides that a court shall take judicial notice of "[d]ecisional, constitutional, and public statutory law and resolutions of the Florida Legislature and the Congress of the United States."

4) Section 90.202(2), Florida Statutes, provides that the court may take judicial notice of "[d]ecisional, constitutional, and public statutory law of every other state, territory, and jurisdiction of the United States."

5) Section 90.202(3), Florida Statutes, provides that the court may take judicial notice of "[c]ontents of the Federal Register."

6) Section 90.202(5), Florida Statutes, provides that the court may take judicial notice of "[o]fficial actions of the legislative, executive, and judicial departments of the United States and of any state, territory, or jurisdiction of the United States."

7) Section 90.202(6), Florida Statutes, provides that a court may take judicial notice of "[r]ecords of any court of this state or of any court of record of the United States or of any state, territory, or jurisdiction of the United States."

8) Section 90.202(11), Florida Statutes, provides that the court may take judicial notice of "[f]acts that are not subject to dispute because they are generally known within the territorial jurisdiction of the court."

9) Section 90.202(12), Florida Statutes, provides that the court may take judicial notice of "[f]acts that are not subject to dispute because they are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned."

Argument

10) The "One Big, Beautiful Bill Act," **(Exhibit A)** was enacted on July 4, 2025, and became Public Law No. 119-21. Section 90.201(1), Florida Statutes. requires the Commission to take judicial notice of this Federal law.

11) Laws of Florida 2024-186 **(Exhibit B)** represents a verbatim publication of a general law enacted by the Florida Legislature in 2024, which includes the "type and strike" legislative text relating to section 377.061, Florida Statutes. Although the Order Establishing Procedure states that, "[o]fficial recognition is hereby taken of decisional, constitutional, and public statutory law and resolutions of the Florida Legislature," OPC asks the

Commission to take mandatory official notice of this specific act that the Florida Legislature passed in 2024.

12) Texas Statute SB 6 **(Exhibit C),** a state law in Texas, was enacted and became effective on June 20, 2025. OPC requests that the Commission take judicial notice of this Texas state law, as allowed by section 90.202(2), Florida Statutes. This law is relevant to the issues in the case surrounding data centers and how to address the load increases they would bring to Florida's grid. The Commission may find the statute useful in making decisions in this docket relating to datacenters and large load customers.

13) Executive Orders 14154, 14156, and 14315 **(Exhibits D, E, and F)** are records of the Federal Register, and section 90.202(3), Florida Statutes, allows the Commission to take judicial notice of the contents of the Federal Register. OPC asks the Commission to take judicial notice of these executive orders because the statements and tone regarding the future of solar energy production could have a direct impact on the reasonableness and prudence of the revenue requirements, solar base rate adjustment mechanisms, and resource adequacy planning methodology put forth by Florida Power & Light ("FPL") in this case. The Commission must be able to consider all available materials that are relevant to the issues in this docket.

14) The United States Treasury guidance relating to the "One Big, Beautiful Bill Act" **(Exhibit G)** will represent official action of the executive department of the United States. Section 90.202(5), Florida Statutes, allows the Commission to take judicial notice of such actions. The Commission should take official recognition of this guidance, once it is issued, as it will be inextricably intertwined with the "One Big, Beautiful Bill Act" and Executive Order No. 14315. That executive order specifically instructed the United States Treasury to:

> [T]ake all action as the Secretary of the Treasury deems necessary and appropriate to strictly enforce the termination of the clean electricity production and investment tax credits under sections 45Y and 48E of the Internal Revenue Code for wind and solar facilities. This includes issuing new and revised guidance as the Secretary of the Treasury deems appropriate and consistent with applicable law to ensure that policies concerning the ''beginning of construction'' are not circumvented, including by preventing the artificial acceleration or manipulation of eligibility and by restricting the use of broad safe harbors unless a substantial portion of a subject facility has been built.

Although the guidance has not yet been issued, it is due to be issued on or before August 18, 2025, which is during the hearing dates for this docket. OPC requests that as soon as that guidance is issued, the Commission take official recognition of that guidance, and any other United States Treasury action resulting from Executive Order 14315 so that the Commission will have the ability to consider all available materials that are relevant to the issues in this docket.

15) Governor DeSantis' veto of Senate Bill 1574 **(Exhibit H)** is an official action of the executive branch of the State of Florida. Section 90.202(5), Florida Statutes, allows the Commission to take judicial notice of such actions. The Commission should take judicial notice of this document because it is relevant to issues surrounding renewable tax credits.

16) FPL's Joint Application for Authorization Under Section 203 of Federal Power Act of Vandolah Power Company LLC et al., under EC25-101 **(Exhibit I)** consists of records of the Federal Energy Regulatory Commission ("FERC"), a Federal regulatory tribunal. Section 90.202(6), Florida Statutes, allows the Commission to take judicial notice of the records of any court in Florida or the United States. Since FERC's resolution of that docket could impact the timing and need of the resource additions requested in this case, these items are relevant to this docket and the Commission should officially recognize them.

17) The written customer comments filed in Florida Public Service Commission Docket 20250011-EI through July 16, 2025, **(Exhibit J)** are records of this Commission, and section 90.202(6), Florida Statutes, allows the Commission to take judicial notice of the contents of any court in Florida or the United States.

Additionally, the Commission encouraged customers at the customer service hearings to submit written comments for the Commission's consideration. One example, of many, when the Commission encouraged customers to submit their written comments for Commission consideration was at the Fort Myers customer service hearing on May 28, 2025, when the Commission stated the following:

> I want to make sure that, you know, if you have more additional comments that you want to make, or your friends or family were not able to make it this morning, you are welcome to email, submit written comments to our offices, and we take those just like you being here today. So the opportunity is not missed if they are not here. There is still opportunity to submit your comments.[1]

Also, the Commission included in the rate case overview published in relation to this docket that any interested person could submit comments or provide information for this matter to the Commission. *(See Attachment 1)*

Since the Commission can only base findings of facts upon evidence in the record or on matters officially recognized, the only way to ensure the Commission's assertion that customer comments will be taken into consideration is to either enter them into evidence or officially recognize the written comments. For the convenience of all parties, OPC has prepared composite **Exhibit J** of all written customer comments filed in this docket

[1] Document No. 04418-2025, p. 5, lines 15-23, Docket No. 20250011-EU, *In re: Petition for rate increase by Florida Power & Light Company.*

submitted up to and including on July 16, 2025, when OPC had to impose a cutoff due to logistical constraints. OPC also requests the opportunity to supplement this exhibit notice/motion with all customer comments provided through the closing of the hearing record. OPC respectfully requests that these written customer comments be officially recognized so that Commission can give each written customer comment the weight that it deserves.

18) The Opinion and Order in Case No. 24-508-EL-ATA **(Exhibit K)** are records of the Public Utilities Commission of Ohio, a regulatory tribunal. Section 90.202(6), Florida Statutes, allows the Commission to take judicial notice of the records of any court in Florida or the United States. The Commission should officially recognize these records because they can assist the Commission in determining how to resolve the issues involving datacenters in this docket since other states, including Ohio, are also dealing with similar issues.

19) FPL's 2016-2024 PSC Annual Reports (**Exhibit L)** are official records of the Commission, a regulatory tribunal. Section 90.202(6), Florida Statutes, allows the Commission to take official recognition of those records. These reports contain information that may be informative to the Commission regarding FPL's historical financial performance.

20) The Congressional letter to Secretary Robert F. Kennedy, Jr, Secretary of Health and Human Services, dated April 4, 2025 **(Exhibit M),** and the Florida Trend magazine article entitled "Florida's Top 10 Private Landowners," published January 16, 2025 **(Exhibit N),** consist of facts that are not subject to dispute and are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned. Section 90.202(6), Florida Statutes, allows the Commission to take official recognition of such documents. **Exhibit M** is relevant to the issues in this docket because both FPL and OPC

witnesses discuss the Low-Income Home Energy Assistance Program ("LIHEAP"), and this document provides important, timely context surrounding the status and future of that program. Additionally, it is not subject to dispute and capable of accurate and ready determination because it is on Congressional letterhead and bears the signatures of 90 members of Congress. **Exhibit N** is relevant to the Plant Held for Future Use issues in this docket, and the data is capable of accurate and ready determination through public property records research throughout Florida's 67 counties.

21) OPC respectfully requests that the Commission officially recognize each of these exhibits so that the information contained in these exhibits can be relied upon by the Commission when determining fair, just, and reasonable rates in this docket. If the Commission officially recognizes these documents, the Commission would then be able to give each exhibit the weight that it deserves. Without officially recognizing these items, the Commission cannot consider these documents unless they are otherwise admitted into evidence in the record. Officially recognizing these documents will also help to save hearing time that will otherwise be spent determining whether to admit each document.

22) This Motion also serves as timely notice to the Commission and all parties of OPC's intent to request official recognition of the records contained in Exhibit A through Exhibit N, in accordance with Paragraph VI(h) of Order No. PSC-2025-0075-PCO-EI.

23) OPC consulted with counsel for all parties regarding their position on this motion. FPL does not oppose the official recognition of Exhibits A, B, C, D, E, F, H, I, J, K, L, or N. FPL does oppose the official recognition of Exhibits G and M. The League of United Latin American Citizens, Florida Rising, the Environmental Confederation of Southwest Florida, the Florida Retail Federation, Floridians Against Increased Rates, and the Florida Industrial

Power Users Group support this motion. The Southern Alliance for Clean Energy, Walmart, the Fuel Retailers, Federal Executive Agencies, Electrify America, EVgo, Armstrong World Industries, Inc., take no position on this motion. The Florida Energy for Innovation Association takes no position pending review of the motion.

WHEREFORE, OPC requests that the Commission grant this Motion for Official Recognition of Exhibits A through Exhibit N.

Respectfully submitted this 24th day of July, 2025.

Walt Trierweiler
Public Counsel

/s/ Mary A. Wessling
Associate Public Counsel
FL Bar No. 93590
Wessling.Mary@leg.state.fl.us

Office of Public Counsel
c/o The Florida Legislature
111 W. Madison Street, Room 812
Tallahassee, FL 32399-1400
(850) 488-9330

Attorney for the Citizens of the State of Florida

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 24th day of July, 2025, to the following:

Shaw Stiller
Timothy Sparks
Florida Public Service Commission
Office of General Counsel
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
sstiller@psc.state.fl.us
tsparks@psc.state.fl.us
discovery-gcl@psc.state.fl.us

Kenneth A. Hoffman
Florida Power & Light Company
134 West Jefferson Street
Tallahassee, FL 32301-1713
ken.hoffman@fpl.com

John T. Burnett
Maria Moncada
Christopher T. Wright
Joel Baker
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
john.t.burnett@fpl.com
maria.moncada@fpl.com
christopher.wright@fpl.com
joel.baker@fpl.com

Jon C. Moyle, Jr.
Karen A. Putnal
Moyle Law Firm, P.A.
118 North Gadsden Street
Tallahassee, FL 32301
jmoyle@moylelaw.com
kputnal@moylelaw.com
mqualls@moylelaw.com

Leslie R. Newton
Ashley N. George
Thomas A. Jernigan
Michael A. Rivera
James B. Ely
Ebony M. Payton
Federal Executive Agencies
139 Barnes Drive, Suite 1
Tyndall Air Force Base, FL 32403
leslie.newton.1@us.af.mil
ashley.george.4@us.af.mil
thomas.jernigan.3@us.af.mil
michael.rivera.51@us.af.mil
james.ely@us.af.mil
ebony.payton.ctr@us.af.mil

Nikhil Vijaykar
Yonatan Moskowitz
Keyes & Fox LLP
580 California St., 12th Floor
San Francisco, CA 94104
nvijaykar@keyesfox.com
ymoskowitz@keyesfox.com

Katelyn Lee
Lindsey Stegall
EVgo Services, LLC
1661 E. Franklin Ave.
El Segundo, CA 90245
katelyn.lee@evgo.com
lindsey.stegall@evgo.com

Bradley Marshall
Jordan Luebkemann
Earthjustice
111 S. Martin Luther King Jr. Blvd.
Tallahassee, FL 32301
bmarshall@earthjustice.org
jluebkemann@earthjustice.org
flcaseupdates@earthjustice.org

Danielle McManamon
Bianca Blanshine
Earthjustice
4500 Biscayne Blvd., Suite 201
Miami, FL 33137
dmcmanamon@earthjustice.org
bblanshine@earthjustice.org

James W. Brew
Laura Wynn Baker
Joseph R. Briscar
Sarah B. Newman
Stone Mattheis Xenopoulos & Brew
1025 Thomas Jefferson St., NW
Suite 800 West
Washington, D.C. 20007
jbrew@smxblaw.com
lwb@smxblaw.com
jrb@smxblaw.com
sbn@smxblaw.com

Stephen Bright
Jigar J. Shah
Electrify America, LLC
1950 Opportunity Way, Suite 1500
Reston, Virginia
steve.bright@electrifyamerica.com
jigar.shah@electrifyamerica.com

Stephanie U. Eaton
Spilman Thomas & Battle
110 Oakwood Drive, Suite 500
Winston-Salem, NC 27103
seaton@spilmanlaw.com

Steven W. Lee
Spilman Thomas & Battle
1100 Bent Creek Blvd., Suite 101
Mechanicsburg, PA 17050
slee@spilmanlaw.com

William C. Garner
Law Office of William C. Garner
3425 Bannerman Road
Unit 105, No. 414
Tallahassee, FL 32312
bgarner@wcglawoffice.com

D. Bruce May
Kevin W. Cox
Kathryn Isted
Holland & Knight LLP
315 S. Calhoun Street, Suite 600
Tallahassee, FL 32301
bruce.may@hklaw.com
kevin.cox@hklaw.com
kathryn.isted@hklaw.com

Robert Scheffel Wright
John T. LaVia, III
Gardner, Bist, Bowden, Dee, LaVia, Wright, Perry & Harper
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com
jlavia@gbwlegal.com

Floyd R. Self
Ruth Vafek
Berger Singerman, LLP
313 N. Monroe Street, Suite 301
Tallahassee, FL 32301
fself@bergersingerman.com
rvafek@bergersingerman.com

Brian A. Ardire
Armstrong World Industries, Inc.
2500 Columbia Avenue
Lancaster, PA 17603
baardire@armstrongceilings.com

Robert E. Montejo
Duane Morris LLP
201 S Biscayne Blvd., Suite 3400
Miami, FL 33131-4325
remontejo@duanemorris.com

Alexander W. Judd
Duane Morris LLP
100 Pearl Street, 13th Floor
Hartford, CT 06103
ajudd@duanemorris.com

<u>/s/ Mary A. Wessling</u>
Mary A. Wessling
Associate Public Counsel
Wessling.Mary@leg.state.fl.us

Attachment 1

Florida Public Service Commission
RATE CASE OVERVIEW

MAY 2025

Petition for rate increase by

Florida Power & Light Company

DOCKET NO. 20250011–EI

On February 28, 2025, Florida Power & Light Company (FPL) filed a petition with the Florida Public Service Commission (Commission or PSC) for a base rate increase. FPL currently provides electric service to approximately 6 million retail customers throughout Northwest and peninsular Florida.

QUESTIONS & ANSWERS

1. Why is FPL requesting a rate increase?

FPL is requesting a rate increase to recover the cost of operating the Utility and allow the company an opportunity to earn a fair rate of return on its investment.

2. When was FPL's last approved rate case?

FPL's last base rate increase was approved in 2021 as part of a settlement agreement.

3. Is there an opportunity for public input on this rate case?

Yes. As part of the evaluation process of FPL's rate request, Commission staff will conduct virtual and in-person service hearings to allow customer feedback about FPL's quality of service and the rate setting process. Comments will be reviewed before the Commission reaches a decision. Commissioners will attend and participate during the service hearings.

To speak at a virtual customer service hearing, a customer must sign up via the PSC's online registration form, which will be available at www.FloridaPSC.com, under the "Hot Topics" heading on the home page. Customers without internet access can sign up to speak by calling the PSC at (850) 413-7080 or emailing speakersignup@psc.state.fl.us. Registration will open on May 20, 2025 at 9:00 a.m., and close at noon on June 2, 2025. One day prior to each virtual service hearing, speakers will be provided further instructions from PSC staff on how to participate.

Customers who wish to speak at the in-person service hearings may register upon arrival at the venue. Online registration is not available for in-person service hearings.

All customers who wish to comment are urged to join the service hearing promptly at the scheduled time because it may be adjourned early if no customers are present to speak or when those present have spoken. Please note that the order in which customers will speak is based on the order in which they register. If you have questions about the sign-up process, please call (850) 413-7080.

4. What if I cannot participate in the service hearings or prefer not to speak? Are there other ways to comment on this case?

Any interested person who wants to comment or provide information to the Commission regarding this matter may do so orally at a customer service hearing or in writing.* Written comments should be mailed to:

Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

The PSC will also accept emailed comments at: clerk@psc.state.fl.us.

Please be sure to include the docket number, **20250011 – EI.**

Comments are placed on the correspondence side of the docket file. In accordance with Florida Statutes, the PSC will also consider FPL's quality of service and other matters. If you have questions, contact the PSC's Office of Consumer Assistance & Outreach at (800) 342-3552.

** Any email or other correspondence sent to a Florida Public Service Commissioner, or any other public official and/or employee of the PSC, in the transaction of public business is considered a public record and is subject to Florida's Public Records Law. This means that Florida law generally requires the PSC to provide a copy of any such email or correspondence, upon request, for inspection and copying to any Florida citizen or to any member of the media.*

QUESTIONS & ANSWERS

5. Can I obtain more information online?

Detailed docket information is available on the PSC website at www.FloridaPSC.com. Click on Clerk's Office then Dockets. Type in the docket number 20250011.

6. How much is the current monthly electric bill for a FPL peninsular and FPL Northwest Florida residential customer using 1,000 kWh?

The current electric bill for a FPL peninsular and FPL Northwest Florida residential customer using 1,000 kWh is $134.14 and $143.60, respectively.

7. How much would the monthly electric bill be for a FPL peninsular and FPL Northwest Florida residential customer using 1,000 kWh?

Using FPL's proposed rates, a January 2026 1,000 kWh monthly bill for FPL peninsular residential customers is estimated to be $134.03 and for FPL Northwest Florida residential customers is estimated to be $138.77. Effective January 2027, a 1,000 kwh monthly bill for FPL peninsular and FPL Northwest Florida residential customers is estimated to be $141.68.

8. Who can answer technical or legal questions?

For technical questions, contact:

Clayton Lewis
Quality of Service and Engineering
(850) 413-6578

Corey Hampson
Rates and Charges
(850) 413-6676

Cassie Gatlin
Accounting
(850) 413-6420

For legal questions, contact:

Shaw Stiller
(850) 413-6187

9. Who provides legal representation for customers in utility related matters before the Public Service Commission?

The Office of Public Counsel (OPC) was established by the Florida Legislature to advocate on behalf of you and other utility customers before the Commission and other state and federal regulatory authorities. OPC is independent from the Commission, and accountable only to the people of the State of Florida through the Florida Legislature. You can reach OPC at (800) 342-0222 or www.floridaopc.gov.

10. When will the PSC make a decision?

After the technical hearing is completed, the PSC staff will file a recommendation with the Commission that addresses FPL's proposed revenue increase. The Commissioners will then vote on this matter at a future Commission Conference.

Based on the Commission's decision on FPL's proposed revenue increase, staff will prepare another recommendation that addresses the specific rates to be charged to each class of customers. The Commission will then vote on FPL's rates at a future Commission Conference.

11. How can I follow the hearings and Commission Conference?

You can watch the hearings and Commission Conference live from the PSC website at www.FloridaPSC.com. Look for the "Watch Live and Archived PSC Events" icon on the left side of the webpage. An audio only option is available by dialing (850) 413-7999. If you are hearing or speech impaired, you may contact the PSC by using the Florida Relay Service at (800) 955-8771 (TDD).

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If cancelled, notice of customer meeting cancellation will be provided on the Commission's website, (*www.FloridaPSC.com*), under Hot Topics found on the home page.
Cancellation can also be confirmed by contacting the Office of General Counsel at (850) 413-6199.

FPSC COMMISSIONERS

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Andrew Giles Fay

COMMISSIONER
Art Graham

CHAIRMAN
Mike La Rosa

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Gary F. Clark

COMMISSIONER
Gabriella Passidomo Smith

FPL Service Hearings	
May 28, 2025 **9:00 a.m. EST** Lee County Civic Center: Davidson House 11831 Bayshore Rd. North Fort Myers, FL 33917 **May 28, 2025** **6:00 p.m. EST*** Florida Memorial University: Lou Rawls Center for the Performing Arts 15800 NW 42nd Avenue Miami Gardens, FL 33054 **May 29, 2025** **9:30 a.m. EST*** Anne Kolb Nature Center: Hollywood North Beach Park 751 Sheridan Street Hollywood, FL 33019 **May 29, 2025** **6:00 p.m. EST** Solid Waste Authority 7501 N Jog Road West Palm Beach, FL 33412	**May 30, 2025** **1:00 p.m. EST** Daytona Beach Shores: Community Center 3000 Bellemead Drive Daytona Beach Shores, FL 32118 **June 3, 2025** **6:00 p.m. EST*** Virtual Public Service Commission **June 4, 2025** **10:00 a.m. EST** **2:00 p.m. EST*** Virtual Public Service Commission **June 5, 2025** **6:00 p.m. CST** Pensacola State College: Hagler Auditorium 1000 College Blvd. Building 2a Pensacola, FL 32504 **June 6, 2025** **1:00 p.m. CST** Gulf Coast State College: Student Union East Room 232 5230 West Highway 98 Panama City, FL 32401
* Denotes Spanish-Language Interpreter Available	

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FPL Peninsular
Residential Bills at Various Usage Levels

	As of February 1, 2025	Estimated January 1, 2026	Estimated January 1, 2027
1,000 kWh			
Base Rate Charges	$ 81.25	$ 92.77	$ 99.82
Fuel Charge	$ 24.08	$ 24.08	$ 24.08
Transition Rider Credit	$ (0.79)	$ (0.40)	$ -
Other Charges[1]	$ 26.14	$ 14.12	$ 14.12
Gross Receipts Tax	$ 3.46	$ 3.46	$ 3.66
Total	**$ 134.14**	**$ 134.03**	**$ 141.68**
1,500 kWh			
Base Rate Charges	$ 122.10	$ 138.70	$ 148.87
Fuel Charge	$ 41.12	$ 41.12	$ 41.12
Transition Rider Credit	$ (1.19)	$ (0.60)	$ -
Other Charges[1]	$ 39.22	$ 21.19	$ 21.19
Gross Receipts Tax	$ 5.34	$ 5.31	$ 5.60
Total	**$ 206.59**	**$ 205.72**	**$ 216.78**
2,000 kWh			
Base Rate Charges	$ 162.95	$ 184.62	$ 197.92
Fuel Charge	$ 58.16	$ 58.16	$ 58.16
Transition Rider Credit	$ (1.58)	$ (0.80)	$ -
Other Charges[1]	$ 52.28	$ 28.24	$ 28.24
Gross Receipts Tax	$ 7.22	$ 7.17	$ 7.55
Total	**$ 279.03**	**$ 277.39**	**$ 291.87**
3,000 kWh			
Base Rate Charges	$ 244.65	$ 276.47	$ 296.02
Fuel Charge	$ 92.24	$ 92.24	$ 92.24
Transition Rider Credit	$ (2.37)	$ (1.20)	$ -
Other Charges[1]	$ 78.42	$ 42.36	$ 42.36
Gross Receipts Tax	$ 10.96	$ 10.88	$ 11.42
Total	**$ 423.90**	**$ 420.75**	**$ 442.04**

[1] Other charges include the energy conservation cost recovery charge, capacity charge, environmental cost recovery charge, storm protection plan charge, and the 2025 interim storm restoration charge. 2026 and 2027 bills include current charges except the storm restoration charge, which will terminate in December 2025.

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FPL Northwest Florida Residential Bills at Various Usage Levels			
1,000 kWh	As of February 1, 2025	Estimated January 1, 2026	Estimated January 1, 2027
Base Rate Charges	$ 81.25	$ 92.77	$ 99.82
Fuel Charge	$ 24.08	$ 24.08	$ 24.08
Transition Rider Charge	$ 8.42	$ 4.21	$ -
Other Charges [1]	$ 26.14	$ 14.12	$ 14.12
Gross Receipts Tax	$ 3.71	$ 3.59	$ 3.66
Total	**$ 143.60**	**$ 138.77**	**$ 141.68**
1,500 kWh			
Base Rate Charges	$ 122.10	$ 138.70	$ 148.87
Fuel Charge Transition	$ 41.12	$ 41.12	$ 41.12
Rider Charge	$ 12.63	$ 6.32	$ -
Other Charges [1]	$ 39.22	$ 21.19	$ 21.19
Gross Receipts Tax	$ 5.71	$ 5.50	$ 5.60
Total	**$ 220.78**	**$ 212.83**	**$ 216.78**
2,000 kWh			
Base Rate Charges	$ 162.95	$ 184.62	$ 197.92
Fuel Charge	$ 58.16	$ 58.16	$ 58.16
Transition Rider Charge	$ 16.84	$ 8.42	$ -
Other Charges [1]	$ 52.28	$ 28.24	$ 28.24
Gross Receipts Tax	$ 7.70	$ 7.41	$ 7.55
Total	**$ 297.93**	**$ 286.85**	**$ 291.87**
3,000 kWh			
Base Rate Charges	$ 244.65	$ 276.47	$ 296.02
Fuel Charge	$ 92.24	$ 92.24	$ 92.24
Transition Rider Charge	$ 25.26	$ 12.63	$ -
Other Charges [1]	$ 78.42	$ 42.36	$ 42.36
Gross Receipts Tax	$ 11.69	$ 11.24	$ 11.42
Total	**$ 452.26**	**$ 434.94**	**$ 442.04**

[1] Other charges include the energy conservation cost recovery charge, capacity charge, environmental cost recovery charge, storm protection plan charge, and the 2025 interim storm restoration charge. 2026 and 2027 bills include current charges except the storm restoration charge, which will terminate in December 2025.

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Petition for rate increase by

Florida Power & Light Company

DOCKET NO. 20250011–EI

Name ____

Address ____

____

To submit your comments about this docket to the Florida Public Service Commission, please complete this comment form and return it by mail, or scan and email to the Commission Clerk at clerk@psc.state.fl.us. Correspondence will be placed in the docket file.

CUSTOMER COMMENTS

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Any email or other correspondence sent to a Florida Public Service Commissioner, or any other public official and/ or employee of the PSC, in the transaction of public business is considered a public record and is subject to Florida's Public Records Law. This means that Florida law generally requires the PSC to provide a copy of any such email or correspondence, upon request, for inspection and copying to any Florida citizen or to any member of the media.

STAMP

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Florida Public Service Commission
Office of Commission Clerk
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

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TAPE HERE

H. R. 1

One Hundred Nineteenth Congress of the United States of America

AT THE FIRST SESSION

Begun and held at the City of Washington on Friday, the third day of January, two thousand and twenty-five

An Act

To provide for reconciliation pursuant to title II of H. Con. Res. 14.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. TABLE OF CONTENTS.

The table of contents of this Act is as follows:

TITLE I—COMMITTEE ON AGRICULTURE, NUTRITION, AND FORESTRY

Subtitle A—Nutrition

SEC. 10101. RE-EVALUATION OF THRIFTY FOOD PLAN.

(a) IN GENERAL.—Section 3 of the Food and Nutrition Act of 2008 (7 U.S.C. 2012) is amended by striking subsection (u) and inserting the following:

"(u) THRIFTY FOOD PLAN.—

"(1) IN GENERAL.—The term 'thrifty food plan' means the diet required to feed a family of 4 persons consisting of a man and a woman ages 20 through 50, a child ages 6 through 8, and a child ages 9 through 11 using the items and quantities of food described in the report of the Department of Agriculture entitled 'Thrifty Food Plan, 2021', and each successor report updated pursuant to this subsection, subject to the conditions that—

"(A) the relevant market baskets of the thrifty food plan shall only be changed pursuant to paragraph (4);

"(B) the cost of the thrifty food plan shall be the basis for uniform allotments for all households, regardless of the actual composition of the household; and

"(C) the cost of the thrifty food plan may only be adjusted in accordance with this subsection.

"(2) HOUSEHOLD ADJUSTMENTS.—The Secretary shall make household adjustments using the following ratios of household size as a percentage of the maximum 4-person allotment:

"(A) For a 1-person household, 30 percent.

"(B) For a 2-person household, 55 percent.

"(C) For a 3-person household, 79 percent.

"(D) For a 4-person household, 100 percent.

"(E) For a 5-person household, 119 percent.

"(F) For a 6-person household, 143 percent.

"(G) For a 7-person household, 158 percent.

"(H) For an 8-person household, 180 percent.

"(I) For a household of 9 persons or more, an additional 22 percent per person, which additional percentage shall not total more than 200 percent.

"(3) ALLOWABLE COST ADJUSTMENTS.—The Secretary shall—

"(A) make cost adjustments in the thrifty food plan for Hawaii and the urban and rural parts of Alaska to reflect the cost of food in Hawaii and urban and rural Alaska;

"(B) make cost adjustments in the separate thrifty food plans for Guam and the Virgin Islands of the United States to reflect the cost of food in those States, but not to exceed the cost of food in the 50 States and the District of Columbia; and

"(C) on October 1, 2025, and on each October 1 thereafter, adjust the cost of the thrifty food plan to reflect changes in the Consumer Price Index for All Urban Consumers, published by the Bureau of Labor Statistics of the Department of Labor, for the most recent 12-month period ending in June.

"(4) RE-EVALUATION OF MARKET BASKETS.—

"(A) RE-EVALUATION.—Not earlier than October 1, 2027, the Secretary may re-evaluate the market baskets of the thrifty food plan based on current food prices, food composition data, consumption patterns, and dietary guidance.

"(B) COST NEUTRALITY.—The Secretary shall not increase the cost of the thrifty food plan based on a re-evaluation under this paragraph.".

(b) CONFORMING AMENDMENTS.—

(1) Section 16(c)(1)(A)(ii)(II) of the Food and Nutrition Act of 2008 (7 U.S.C. 2025(c)(1)(A)(ii)(II)) is amended by striking "section 3(u)(4)" and inserting "section 3(u)(3)".

(2) Section 19(a)(2)(A)(ii) of the Food and Nutrition Act of 2008 (7 U.S.C. 2028(a)(2)(A)(ii)) is amended by striking "section 3(u)(4)" and inserting "section 3(u)(3)".

(3) Section 27(a)(2) of the Food and Nutrition Act of 2008 (7 U.S.C. 2036(a)(2))) is amended by striking "section 3(u)(4)" each place it appears and inserting "section 3(u)(3)".

SEC. 10102. MODIFICATIONS TO SNAP WORK REQUIREMENTS FOR ABLE-BODIED ADULTS.

(a) EXCEPTIONS.—Section 6(o) of the Food and Nutrition Act of 2008 (7 U.S.C. 2015(o)) is amended by striking paragraph (3) and inserting the following:

"(3) EXCEPTIONS.—Paragraph (2) shall not apply to an individual if the individual is—

"(A) under 18, or over 65, years of age;

"(B) medically certified as physically or mentally unfit for employment;

"(C) a parent or other member of a household with responsibility for a dependent child under 14 years of age;

"(D) otherwise exempt under subsection (d)(2);

"(E) a pregnant woman;

"(F) an Indian or an Urban Indian (as such terms are defined in paragraphs (13) and (28) of section 4 of the Indian Health Care Improvement Act); or

"(G) a California Indian described in section 809(a) of the Indian Health Care Improvement Act.".

(b) STANDARDIZING ENFORCEMENT.—Section 6(o)(4) of the Food and Nutrition Act of 2008 (7 U.S.C. 2015(o)(4)) is amended—

(1) in subparagraph (A), by striking clause (ii) and inserting the following:

"(ii) is in a noncontiguous State and has an unemployment rate that is at or above 1.5 times the national unemployment rate."; and

(2) by adding at the end the following:

"(C) DEFINITION OF NONCONTIGUOUS STATE.—

"(i) IN GENERAL.—In this paragraph, the term 'noncontiguous State' means a State that is not 1 of the contiguous 48 States or the District of Columbia.

"(ii) EXCLUSIONS.—The term 'noncontiguous State' does not include Guam or the Virgin Islands of the United States.".

(c) WAIVER FOR NONCONTIGUOUS STATES.—Section 6(o) of the Food and Nutrition Act of 2008 (7 U.S.C. 2015(o)) is amended—

(1) by redesignating paragraph (7) as paragraph (8); and

(2) by inserting after paragraph (6) the following:

"(7) EXEMPTION FOR NONCONTIGUOUS STATES.—

"(A) DEFINITION OF NONCONTIGUOUS STATE.—

"(i) IN GENERAL.—In this paragraph, the term 'noncontiguous State' means a State that is not 1 of the contiguous 48 States or the District of Columbia.

"(ii) EXCLUSIONS.—In this paragraph, the term 'noncontiguous State' does not include Guam or the Virgin Islands of the United States.

"(B) EXEMPTION.—Subject to subparagraph (D), the Secretary may exempt individuals in a noncontiguous State from compliance with the requirements of paragraph (2) if—

"(i) the State agency submits to the Secretary a request for that exemption, made in such form and at such time as the Secretary may require, and including the information described in subparagraph (C); and

"(ii) the Secretary determines that based on that request, the State agency is demonstrating a good faith effort to comply with the requirements of paragraph (2).

"(C) GOOD FAITH EFFORT DETERMINATION.—In determining whether a State agency is demonstrating a good faith effort for purposes of subparagraph (B)(ii), the Secretary shall consider—

"(i) any actions taken by the State agency toward compliance with the requirements of paragraph (2);

"(ii) any significant barriers to or challenges in meeting those requirements, including barriers or challenges relating to funding, design, development, procurement, or installation of necessary systems or resources;

"(iii) the detailed plan and timeline of the State agency for achieving full compliance with those requirements, including any milestones (as defined by the Secretary); and "(iv) any other criteria determined appropriate by the Secretary.

"(D) DURATION OF EXEMPTION.—

"(i) IN GENERAL.—An exemption granted under subparagraph (B) shall expire not later than December 31, 2028, and may not be renewed beyond that date.

"(ii) EARLY TERMINATION.—The Secretary may terminate an exemption granted under subparagraph (B) prior to the expiration date of that exemption if the Secretary determines that the State agency—

"(I) has failed to comply with the reporting requirements described in subparagraph (E); or

"(II) based on the information provided pursuant to subparagraph (E), failed to make continued good faith efforts toward compliance with the requirements of this subsection.

"(E) REPORTING REQUIREMENTS.—A State agency granted an exemption under subparagraph (B) shall submit to the Secretary—

"(i) quarterly progress reports on the status of the State agency in achieving the milestones toward full compliance described in subparagraph (C)(iii); and

"(ii) information on specific risks or newly identified barriers or challenges to full compliance, including the plan of the State agency to mitigate those risks, barriers, or challenges.".

SEC. 10103. AVAILABILITY OF STANDARD UTILITY ALLOWANCES BASED ON RECEIPT OF ENERGY ASSISTANCE.

(a) STANDARD UTILITY ALLOWANCE.—Section 5(e)(6)(C)(iv)(I) of the Food and Nutrition Act of 2008 (7 U.S.C. 2014(e)(6)(C)(iv)(I)) is amended by inserting "with an elderly or disabled member" after "households".

(b) THIRD-PARTY ENERGY ASSISTANCE PAYMENTS.—Section 5(k)(4) of the Food and Nutrition Act of 2008 (7 U.S.C. 2014(k)(4)) is amended—

(1) in subparagraph (A), by inserting "without an elderly or disabled member" before "shall be"; and

(2) in subparagraph (B), by inserting "with an elderly or disabled member" before "under a State law".

SEC. 10104. RESTRICTIONS ON INTERNET EXPENSES.

Section 5(e)(6) of the Food and Nutrition Act of 2008 (7 U.S.C. 2014(e)(6)) is amended by adding at the end the following:

"(E) RESTRICTIONS ON INTERNET EXPENSES.—Any service fee associated with internet connection shall not be used in computing the excess shelter expense deduction under this paragraph.".

SEC. 10105. MATCHING FUNDS REQUIREMENTS.

(a) IN GENERAL.—Section 4(a) of the Food and Nutrition Act of 2008 (7 U.S.C. 2013(a)) is amended—

(1) by striking "(a) Subject to" and inserting the following:

"(a) PROGRAM.—

"(1) ESTABLISHMENT.—Subject to"; and

(2) by adding at the end the following:

"(2) STATE QUALITY CONTROL INCENTIVE.—

"(A) DEFINITION OF PAYMENT ERROR RATE.—In this paragraph, the term 'payment error rate' has the meaning given the term in section 16(c)(2).

"(B) STATE COST SHARE.—

"(i) IN GENERAL.—Subject to clause (iii), beginning in fiscal year 2028, if the payment error rate of a State as determined under clause (ii) is—

"(I) less than 6 percent, the Federal share of the cost of the allotment described in paragraph (1) for that State in a fiscal year shall be 100 percent, and the State share shall be 0 percent;

"(II) equal to or greater than 6 percent but less than 8 percent, the Federal share of the cost of the allotment described in paragraph (1) for that State in a fiscal year shall be 95 percent, and the State share shall be 5 percent;

"(III) equal to or greater than 8 percent but less than 10 percent, the Federal share of the cost of the allotment described in paragraph (1) for that State in a fiscal year shall be 90 percent, and the State share shall be 10 percent; and

"(IV) equal to or greater than 10 percent, the Federal share of the cost of the allotment described in paragraph (1) for that State in a fiscal year shall be 85 percent, and the State share shall be 15 percent.

"(ii) ELECTIONS.—

"(I) FISCAL YEAR 2028.—For fiscal year 2028, to calculate the applicable State share under clause (i), a State may elect to use the payment error rate of the State from fiscal year 2025 or 2026.

"(II) FISCAL YEAR 2029 AND THEREAFTER.—For fiscal year 2029 and each fiscal year thereafter, to calculate the applicable State share under clause (i), the Secretary shall use the payment error rate of the State for the third fiscal year preceding the fiscal year for which the State share is being calculated.

"(iii) DELAYED IMPLEMENTATION.—

"(I) FISCAL YEAR 2025.—If, for fiscal year 2025, the payment error rate of a State multiplied by 1.5 is equal to or above 20 percent, the implementation date under clause (i) for that State shall be fiscal year 2029.

"(II) FISCAL YEAR 2026.—If, for fiscal year 2026, the payment error rate of a State multiplied by 1.5 is equal to or above 20 percent, the implementation date under clause (i) for that State shall be fiscal year 2030.

"(3) MAXIMUM FEDERAL PAYMENT.—The Secretary may not pay towards the cost of an allotment described in paragraph (1) an amount that is greater than the applicable Federal share under paragraph (2).".

(b) LIMITATION ON AUTHORITY.—Section 13(a)(1) of the Food and Nutrition Act of 2008 (7 U.S.C. 2022(a)(1)) is amended in the first sentence by inserting “or the payment or disposition of a State share under section 4(a)(2)” after “16(c)(1)(D)(i)(II)”.

SEC. 10106. ADMINISTRATIVE COST SHARING.

Section 16(a) of the Food and Nutrition Act of 2008 (7 U.S.C. 2025(a)) is amended in the matter preceding paragraph (1) by striking “agency an amount equal to 50 per centum” and inserting “agency, through fiscal year 2026, 50 percent, and for fiscal year 2027 and each fiscal year thereafter, 25 percent,”.

SEC. 10107. NATIONAL EDUCATION AND OBESITY PREVENTION GRANT PROGRAM.

Section 28(d)(1)(F) of the Food and Nutrition Act of 2008 (7 U.S.C. 2036a(d)(1)(F)) is amended by striking “for fiscal year 2016 and each subsequent fiscal year” and inserting “for each of fiscal years 2016 through 2025”.

SEC. 10108. ALIEN SNAP ELIGIBILITY.

Section 6(f) of the Food and Nutrition Act of 2008 (7 U.S.C. 2015(f)) is amended to read as follows:

“(f) No individual who is a member of a household otherwise eligible to participate in the supplemental nutrition assistance program under this section shall be eligible to participate in the supplemental nutrition assistance program as a member of that or any other household unless he or she is—

“(1) a resident of the United States; and

“(2) either—

“(A) a citizen or national of the United States;

“(B) an alien lawfully admitted for permanent residence as an immigrant as defined by sections 101(a)(15) and 101(a)(20) of the Immigration and Nationality Act, excluding, among others, alien visitors, tourists, diplomats, and students who enter the United States temporarily with no intention of abandoning their residence in a foreign country;

“(C) an alien who has been granted the status of Cuban and Haitian entrant, as defined in section 501(e) of the Refugee Education Assistance Act of 1980 (Public Law 96–422); or

“(D) an individual who lawfully resides in the United States in accordance with a Compact of Free Association referred to in section 402(b)(2)(G) of the Personal Responsibility and Work Opportunity Reconciliation Act of 1996.

The income (less, at State option, a pro rata share) and financial resources of the individual rendered ineligible to participate in the supplemental nutrition assistance program under this subsection shall be considered in determining the eligibility and the value of the allotment of the household of which such individual is a member.”.

Subtitle B—Forestry

SEC. 10201. RESCISSION OF AMOUNTS FOR FORESTRY.

The unobligated balances of amounts appropriated by the following provisions of Public Law 117–169 are rescinded:

(1) Paragraphs (3) and (4) of section 23001(a) (136 Stat. 2023).

(2) Paragraphs (1) through (4) of section 23002(a) (136 Stat. 2025).

(3) Section 23003(a)(2) (136 Stat. 2026).

(4) Section 23005 (136 Stat. 2027).

Subtitle C—Commodities

SEC. 10301. EFFECTIVE REFERENCE PRICE; REFERENCE PRICE.

(a) EFFECTIVE REFERENCE PRICE.—Section 1111(8)(B)(ii) of the Agricultural Act of 2014 (7 U.S.C. 9011(8)(B)(ii)) is amended by striking "85" and inserting "beginning with the crop year 2025, 88".

(b) REFERENCE PRICE.—Section 1111 of the Agricultural Act of 2014 (7 U.S.C. 9011) is amended by striking paragraph (19) and inserting the following:

"(19) REFERENCE PRICE.—

"(A) IN GENERAL.—Effective beginning with the 2025 crop year, subject to subparagraphs (B) and (C), the term 'reference price', with respect to a covered commodity for a crop year, means the following:

"(i) For wheat, $6.35 per bushel.

"(ii) For corn, $4.10 per bushel.

"(iii) For grain sorghum, $4.40 per bushel.

"(iv) For barley, $5.45 per bushel.

"(v) For oats, $2.65 per bushel.

"(vi) For long grain rice, $16.90 per hundredweight.

"(vii) For medium grain rice, $16.90 per hundredweight.

"(viii) For soybeans, $10.00 per bushel.

"(ix) For other oilseeds, $23.75 per hundredweight.

"(x) For peanuts, $630.00 per ton.

"(xi) For dry peas, $13.10 per hundredweight.

"(xii) For lentils, $23.75 per hundredweight.

"(xiii) For small chickpeas, $22.65 per hundredweight.

"(xiv) For large chickpeas, $25.65 per hundredweight.

"(xv) For seed cotton, $0.42 per pound.

"(B) EFFECTIVENESS.—Effective beginning with the 2031 crop year, the reference prices defined in subparagraph (A) with respect to a covered commodity shall equal the reference price in the previous crop year multiplied by 1.005.

"(C) LIMITATION.—In no case shall a reference price for a covered commodity exceed 113 percent of the reference price for such covered commodity listed in subparagraph (A).".

SEC. 10302. BASE ACRES.

Section 1112 of the Agricultural Act of 2014 (7 U.S.C. 9012) is amended—

(1) in subsection (d)(3)(A), by striking "2023" and inserting "2031"; and

(2) by adding at the end the following:

"(e) ADDITIONAL BASE ACRES.—

"(1) IN GENERAL.—As soon as practicable after the date of enactment of this subsection, and notwithstanding subsection (a), the Secretary shall provide notice to owners of eligible farms pursuant to paragraph (3) and allocate to those eligible farms a total of not more than an additional 30,000,000 base acres in the manner provided in this subsection. An owner of a farm that is eligible to receive an allocation of base acres may elect to not receive that allocation by notifying the Secretary not later than 90 days after receipt of the notice provided by the Secretary under this paragraph.

"(2) CONTENT OF NOTICE.—The notice under paragraph (1) shall include the following:

"(A) Information that the allocation is occurring.

"(B) Information regarding the eligibility of the farm for an allocation of base acres under paragraph (3).

"(C) Information regarding how an owner may appeal a determination of ineligibility for an allocation of base acres under paragraph (3) through an appeals process established by the Secretary.

"(3) ELIGIBILITY.—

"(A) IN GENERAL.—Subject to subparagraph (D), effective beginning with the 2026 crop year, a farm is eligible to receive an allocation of base acres if, with respect to the farm, the amount described in subparagraph (B) exceeds the amount described in subparagraph (C).

"(B) 5-YEAR AVERAGE SUM.—The amount described in this subparagraph, with respect to a farm, is the sum of—

"(i) the 5-year average of—

"(I) the acreage planted on the farm to all covered commodities for harvest, grazing, haying, silage or other similar purposes for the 2019 through 2023 crop years; and

"(II) any acreage on the farm that the producers were prevented from planting during the 2019 through 2023 crop years to covered commodities because of drought, flood, or other natural disaster, or other condition beyond the control of the producers, as determined by the Secretary; plus

"(ii) the lesser of—

"(I) 15 percent of the total acres on the farm; and

"(II) the 5-year average of—

"(aa) the acreage planted on the farm to eligible noncovered commodities for harvest, grazing, haying, silage, or other similar purposes for the 2019 through 2023 crop years; and

"(bb) any acreage on the farm that the producers were prevented from planting during the 2019 through 2023 crop years to eligible noncovered commodities because of drought, flood, or other natural disaster, or other condition beyond the control of the producers, as determined by the Secretary.

"(C) TOTAL NUMBER OF BASE ACRES FOR COVERED COMMODITIES.—The amount described in this subparagraph, with respect to a farm, is the total number of base acres for covered commodities on the farm (excluding unassigned crop base), as in effect on September 30, 2024.

"(D) EFFECT OF NO RECENT PLANTINGS OF COVERED COMMODITIES.—In the case of a farm for which the amount determined under clause (i) of subparagraph (B) is equal to zero, that farm shall be ineligible to receive an allocation of base acres under this subsection.

"(E) ACREAGE PLANTED ON THE FARM TO ELIGIBLE NONCOVERED COMMODITIES DEFINED.—In this paragraph, the term 'acreage planted on the farm to eligible noncovered commodities' means acreage planted on a farm to commodities other than covered commodities, trees, bushes, vines, grass, or pasture (including cropland that was idle or fallow), as determined by the Secretary.

"(4) NUMBER OF BASE ACRES.—Subject to paragraphs (3) and (8), the number of base acres allocated to an eligible farm shall—

"(A) be equal to the difference obtained by subtracting the amount determined under subparagraph (C) of paragraph (3) from the amount determined under subparagraph (B) of that paragraph; and

"(B) include unassigned crop base.

"(5) ALLOCATION OF ACRES.—

"(A) ALLOCATION.—The Secretary shall allocate the number of base acres under paragraph (4) among those covered commodities planted on the farm at any time during the 2019 through 2023 crop years.

"(B) ALLOCATION FORMULA.—The allocation of additional base acres for covered commodities shall be in proportion to the ratio of—

"(i) the 5-year average of—

"(I) the acreage planted on the farm to each covered commodity for harvest, grazing, haying, silage, or other similar purposes for the 2019 through 2023 crop years; and

"(II) any acreage on the farm that the producers were prevented from planting during the 2019 through 2023 crop years to that covered commodity because of drought, flood, or other natural disaster, or other condition beyond the control of the producers, as determined by the Secretary; to

"(ii) the 5-year average determined under paragraph (3)(B)(i).

"(C) INCLUSION OF ALL 5 YEARS IN AVERAGE.—For the purpose of determining a 5-year acreage average under subparagraph (B) for a farm, the Secretary shall not exclude any crop year in which a covered commodity was not planted.

"(D) TREATMENT OF MULTIPLE PLANTING OR PREVENTED PLANTING.—For the purpose of determining under subparagraph (B) the acreage on a farm that producers planted or were prevented from planting during the 2019 through 2023 crop years to covered commodities, if the acreage that was planted or prevented from being planted was devoted to another covered commodity in the same crop year (other than a covered commodity produced under an established practice of double cropping), the owner may elect the covered commodity to be used for that crop year in determining the 5-year average, but may not include both the initial covered commodity and the subsequent covered commodity.

"(E) LIMITATION.—The allocation of additional base acres among covered commodities on a farm under this paragraph may not result in a total number of base acres for the farm in excess of the total number of acres on the farm.

"(6) REDUCTION BY THE SECRETARY.—In carrying out this subsection, if the total number of eligible acres allocated to base acres across all farms in the United States under this subsection would exceed 30,000,000 acres, the Secretary shall apply an across-the-board, pro-rata reduction to the number of eligible acres to ensure the number of allocated base acres under this subsection is equal to 30,000,000 acres.

"(7) PAYMENT YIELD.—Beginning with crop year 2026, for the purpose of making price loss coverage payments under section 1116, the Secretary shall establish payment yields to base acres allocated under this subsection equal to—

"(A) the payment yield established on the farm for the applicable covered commodity; and

"(B) if no such payment yield for the applicable covered commodity exists, a payment yield—

"(i) equal to the average payment yield for the covered commodity for the county in which the farm is situated; or

"(ii) determined pursuant to section 1113(c).

"(8) TREATMENT OF NEW OWNERS.—In the case of a farm for which the owner on the date of enactment of this subsection was not the owner for the 2019 through 2023 crop years, the Secretary shall use the planting history of the prior owner or owners of that farm for purposes of determining—

"(A) eligibility under paragraph (3);

"(B) eligible acres under paragraph (4); and

"(C) the allocation of acres under paragraph (5).".

SEC. 10303. PRODUCER ELECTION.

(a) IN GENERAL.—Section 1115 of the Agricultural Act of 2014 (7 U.S.C. 9015) is amended—

(1) in subsection (a), in the matter preceding paragraph (1), by striking "2023" and inserting "2031";

(2) in subsection (c)—

(A) in the matter preceding paragraph (1)—

(i) by striking "crop year or" and inserting "crop year,"; and

(ii) by inserting "or the 2026 crop year," after "2019 crop year,";

(B) in paragraph (1)—

(i) by striking "crop year or" and inserting "crop year,"; and

(ii) by inserting "or the 2026 crop year," after "2019 crop year,"; and

(C) in paragraph (2)—

(i) in subparagraph (A), by striking "and" at the end;

(ii) in subparagraph (B), by striking the period at the end and inserting "; and"; and

(iii) by adding at the end the following:

"(C) the same coverage for each covered commodity on the farm for the 2027 through 2031 crop years as was applicable for the 2025 crop year."; and

(3) by adding at the end the following:

"(i) HIGHER OF PRICE LOSS COVERAGE PAYMENTS AND AGRICULTURE RISK COVERAGE PAYMENTS.—For the 2025 crop year, the Secretary shall, on a covered commodity-by-covered commodity basis, make the higher of price loss coverage payments under section 1116 and agriculture risk coverage county coverage payments under section 1117 to the producers on a farm for the payment acres for each covered commodity on the farm.".

(b) FEDERAL CROP INSURANCE SUPPLEMENTAL COVERAGE OPTION.—Section 508(c)(4)(C)(iv) of the Federal Crop Insurance Act (7 U.S.C. 1508(c)(4)(C)(iv)) is amended by striking "Crops for which the producer has elected under section 1116 of the Agricultural Act of 2014 to receive agriculture risk coverage and acres" and inserting "Acres".

SEC. 10304. PRICE LOSS COVERAGE.

Section 1116 of the Agricultural Act of 2014 (7 U.S.C. 9016) is amended—

(1) in subsection (a)(2), in the matter preceding subparagraph (A), by striking "2023" and inserting "2031";

(2) in subsection (c)(1)(B)—

(A) in the subparagraph heading, by striking "2023" and inserting "2031"; and

(B) in the matter preceding clause (i), by striking "2023" and inserting "2031";

(3) in subsection (d), in the matter preceding paragraph (1), by striking "2025" and inserting "2031"; and

(4) in subsection (g)—

(A) by striking "subparagraph (F) of section 1111(19)" and inserting "paragraph (19)(A)(vi) of section 1111"; and

(B) by striking "2012 through 2016" each place it appears and inserting "2017 through 2021".

SEC. 10305. AGRICULTURE RISK COVERAGE.

Section 1117 of the Agricultural Act of 2014 (7 U.S.C. 9017) is amended—

(1) in subsection (a), in the matter preceding paragraph (1), by striking "2023" and inserting "2031";

(2) in subsection (c)—

(A) in paragraph (1), by inserting "for each of the 2014 through 2024 crop years and 90 percent of the benchmark revenue for each of the 2025 through 2031 crop years" before the period at the end;

(B) by striking "2023" each place it appears and inserting "2031"; and

(C) in paragraph (4)(B), in the subparagraph heading, by striking "2023" and inserting "2031";

(3) in subsection (d)(1), by striking subparagraph (B) and inserting the following:

"(B)(i) for each of the 2014 through 2024 crop years, 10 percent of the benchmark revenue for the crop year applicable under subsection (c); and

"(ii) for each of the 2025 through 2031 crop years, 12 percent of the benchmark revenue for the crop year applicable under subsection (c)."; and

(4) in subsections (e), (g)(5), and (i)(5), by striking "2023" each place it appears and inserting "2031".

SEC. 10306. EQUITABLE TREATMENT OF CERTAIN ENTITIES.

(a) IN GENERAL.—Section 1001 of the Food Security Act of 1985 (7 U.S.C. 1308) is amended—

(1) in subsection (a)—

(A) by redesignating paragraph (5) as paragraph (6); and

(B) by inserting after paragraph (4) the following:

"(5) QUALIFIED PASS-THROUGH ENTITY.—The term 'qualified pass-through entity' means—

"(A) a partnership (within the meaning of subchapter K of chapter 1 of the Internal Revenue Code of 1986);

"(B) an S corporation (as defined in section 1361 of that Code);

"(C) a limited liability company that does not affirmatively elect to be treated as a corporation; and

"(D) a joint venture or general partnership.";

(2) in subsections (b) and (c), by striking "except a joint venture or general partnership" each place it appears and inserting "except a qualified pass-through entity"; and

(3) in subsection (d), by striking "subtitle B of title I of the Agricultural Act of 2014 or".

(b) ATTRIBUTION OF PAYMENTS.—Section 1001(e)(3)(B)(ii) of the Food Security Act of 1985 (7 U.S.C. 1308(e)(3)(B)(ii)) is amended—

(1) in the clause heading, by striking "JOINT VENTURES AND GENERAL PARTNERSHIPS" and inserting "QUALIFIED PASS-THROUGH ENTITIES";

(2) by striking "a joint venture or a general partnership" and inserting "a qualified pass-through entity";

(3) by striking "joint ventures and general partnerships" and inserting "qualified pass-through entities"; and

(4) by striking "the joint venture or general partnership" and inserting "the qualified pass-through entity".

(c) PERSONS ACTIVELY ENGAGED IN FARMING.—Section 1001A(b)(2) of the Food Security Act of 1985 (7 U.S.C. 1308–1(b)(2)) is amended—

(1) subparagraphs (A) and (B), by striking "a general partnership, a participant in a joint venture" each place it appears and inserting "a qualified pass-through entity"; and

(2) in subparagraph (C), by striking "a general partnership, joint venture, or similar entity" and inserting "a qualified pass-through entity or a similar entity".

(d) JOINT AND SEVERAL LIABILITY.—Section 1001B(d) of the Food Security Act of 1985 (7 U.S.C. 1308–2(d)) is amended by striking "partnerships and joint ventures" and inserting "qualified pass-through entities".

(e) EXCLUSION FROM AGI CALCULATION.—Section 1001D(d) of the Food Security Act of 1985 (7 U.S.C. 1308–3a(d)) is amended by striking ", general partnership, or joint venture" each place it appears.

SEC. 10307. PAYMENT LIMITATIONS.

Section 1001 of the Food Security Act of 1985 (7 U.S.C. 1308) is amended—

(1) in subsection (b)—

(A) by striking "The" and inserting "Subject to subsection (i), the"; and

(B) by striking "$125,000" and inserting "$155,000";

(2) in subsection (c)—

(A) by striking "The" and inserting "Subject to subsection (i), the"; and

(B) by striking "$125,000" and inserting "$155,000"; and

(3) by adding at the end the following:

"(i) ADJUSTMENT.—For the 2025 crop year and each crop year thereafter, the Secretary shall annually adjust the amounts described in subsections (b) and (c) for inflation based on the Consumer Price Index for All Urban Consumers published by the Bureau of Labor Statistics of the Department of Labor.".

SEC. 10308. ADJUSTED GROSS INCOME LIMITATION.

Section 1001D(b) of the Food Security Act of 1985 (7 U.S.C. 1308–3a(b)) is amended—

(1) in paragraph (1), by striking "paragraph (3)" and inserting "paragraphs (3) and (4)"; and

(2) by adding at the end the following:

"(4) EXCEPTION FOR CERTAIN OPERATIONS.—

"(A) DEFINITIONS.—In this paragraph:

"(i) EXCEPTED PAYMENT OR BENEFIT.—The term 'excepted payment or benefit' means—

"(I) a payment or benefit under subtitle E of title I of the Agricultural Act of 2014 (7 U.S.C. 9081 et seq.);

"(II) a payment or benefit under section 196 of the Federal Agriculture Improvement and Reform Act of 1996 (7 U.S.C. 7333); and

"(III) a payment or benefit described in paragraph (2)(C) received on or after October 1, 2024.

"(ii) FARMING, RANCHING, OR SILVICULTURE ACTIVITIES.—The term 'farming, ranching, or silviculture activities' includes agri-tourism, direct-to-consumer marketing of agricultural products, the sale of agricultural equipment owned by the person or legal entity, and other agriculture-related activities, as determined by the Secretary.

"(B) EXCEPTION.—In the case of an excepted payment or benefit, the limitation established by paragraph (1) shall not apply to a person or legal entity during a crop, fiscal, or program year, as appropriate, if greater than or equal to 75 percent of the average gross income of the person or legal entity derives from farming, ranching, or silviculture activities.".

SEC. 10309. MARKETING LOANS.

(a) AVAILABILITY OF NONRECOURSE MARKETING ASSISTANCE LOANS FOR LOAN COMMODITIES.—Section 1201(b)(1) of the Agricultural Act of 2014 (7 U.S.C. 9031(b)(1)) is amended by striking "2023" and inserting "2031".

(b) LOAN RATES FOR NONRECOURSE MARKETING ASSISTANCE LOANS.—Section 1202 of the Agricultural Act of 2014 (7 U.S.C. 9032) is amended—

(1) in subsection (b)—

(A) in the subsection heading, by striking "2023" and inserting "2025"; and

(B) in the matter preceding paragraph (1), by striking "2023" and inserting "2025";

(2) by redesignating subsections (c) and (d) as subsections (d) and (e), respectively;

(3) by inserting after subsection (b) the following:

"(c) 2026 THROUGH 2031 CROP YEARS.—For purposes of each of the 2026 through 2031 crop years, the loan rate for a marketing assistance loan under section 1201 for a loan commodity shall be equal to the following:

"(1) In the case of wheat, $3.72 per bushel.

"(2) In the case of corn, $2.42 per bushel.

"(3) In the case of grain sorghum, $2.42 per bushel.

"(4) In the case of barley, $2.75 per bushel.

"(5) In the case of oats, $2.20 per bushel.

"(6) In the case of upland cotton, $0.55 per pound.

"(7) In the case of extra long staple cotton, $1.00 per pound.

"(8) In the case of long grain rice, $7.70 per hundredweight.

"(9) In the case of medium grain rice, $7.70 per hundredweight.

"(10) In the case of soybeans, $6.82 per bushel.

"(11) In the case of other oilseeds, $11.10 per hundredweight for each of the following kinds of oilseeds:

"(A) Sunflower seed.

"(B) Rapeseed.

"(C) Canola.

"(D) Safflower.

"(E) Flaxseed.

"(F) Mustard seed.

"(G) Crambe.

"(H) Sesame seed.

"(I) Other oilseeds designated by the Secretary.

"(12) In the case of dry peas, $6.87 per hundredweight.

"(13) In the case of lentils, $14.30 per hundredweight.

"(14) In the case of small chickpeas, $11.00 per hundredweight.

"(15) In the case of large chickpeas, $15.40 per hundredweight.

"(16) In the case of graded wool, $1.60 per pound.

"(17) In the case of nongraded wool, $0.55 per pound.

"(18) In the case of mohair, $5.00 per pound.

"(19) In the case of honey, $1.50 per pound.

"(20) In the case of peanuts, $390 per ton.";

(4) in subsection (d) (as so redesignated), by striking "(a)(11) and (b)(11)" and inserting "(a)(11), (b)(11), and (c)(11)"; and

(5) in subsection (e) (as so redesignated), in paragraph (1), by striking "$0.25" and inserting "$0.30".

(c) PAYMENT OF COTTON STORAGE COSTS.—Section 1204(g) of the Agricultural Act of 2014 (7 U.S.C. 9034(g)) is amended—

(1) by striking "Effective" and inserting the following:

"(1) CROP YEARS 2014 THROUGH 2025.—Effective";

(2) in paragraph (1) (as so designated), by striking "2023" and inserting "2025"; and

(3) by adding at the end the following:

"(2) PAYMENT OF COTTON STORAGE COSTS.—Effective for each of the 2026 through 2031 crop years, the Secretary shall make cotton storage payments for upland cotton and extra long staple cotton available in the same manner as the Secretary provided storage payments for the 2006 crop of upland cotton, except that the payment rate shall be equal to the lesser of—

"(A) the submitted storage charge for the current marketing year; and

"(B) in the case of storage in—

"(i) California or Arizona, a payment rate of $4.90; and

"(ii) any other State, a payment rate of $3.00.".

(d) LOAN DEFICIENCY PAYMENTS.—

(1) CONTINUATION.—Section 1205(a)(2)(B) of the Agricultural Act of 2014 (7 U.S.C. 9035(a)(2)(B)) is amended by striking "2023" and inserting "2031".

(2) PAYMENTS IN LIEU OF LDPS.—Section 1206 of the Agricultural Act of 2014 (7 U.S.C. 9036) is amended, in subsections (a) and (d), by striking "2023" each place it appears and inserting "2031".

(e) SPECIAL COMPETITIVE PROVISIONS FOR EXTRA LONG STAPLE COTTON.—Section 1208(a) of the Agricultural Act of 2014 (7 U.S.C. 9038(a)) is amended, in the matter preceding paragraph (1), by striking "2026" and inserting "2032".

(f) AVAILABILITY OF RECOURSE LOANS.—Section 1209 of the Agricultural Act of 2014 (7 U.S.C. 9039) is amended, in subsections (a)(2), (b), and (c), by striking "2023" each place it appears and inserting "2031".

SEC. 10310. REPAYMENT OF MARKETING LOANS.

Section 1204 of the Agricultural Act of 2014 (7 U.S.C. 9034) is amended—

(1) in subsection (b)—

(A) by redesignating paragraph (1) as subparagraph (A) and indenting appropriately;

(B) in the matter preceding subparagraph (A) (as so redesignated), by striking "The Secretary" and inserting the following:

"(1) IN GENERAL.—The Secretary"; and

(C) by striking paragraph (2) and inserting the following:

"(B)(i) in the case of long grain rice and medium grain rice, the prevailing world market price for the commodity, as determined and adjusted by the Secretary in accordance with this section; or "(ii) in the case of upland cotton, the prevailing world market price for the commodity, as determined and adjusted by the Secretary in accordance with this section.

"(2) REFUND FOR UPLAND COTTON.—In the case of a repayment for a marketing assistance loan for upland cotton at a rate described in paragraph (1)(B)(ii), the Secretary shall provide to the producer a refund (if any) in an amount equal to the difference between the lowest prevailing world market price, as determined and adjusted by the Secretary in accordance with this section, during the 30-day period following the date on which the producer repays the marketing assistance loan and the repayment rate.";

(2) in subsection (c)—

(A) by striking the period at the end and inserting "; and";

(B) by striking "at the loan rate" and inserting the following: ″at a rate that is the lesser of— "

"(1) the loan rate"; and

(C) by adding at the end the following:

"(2) the prevailing world market price for the commodity, as determined and adjusted by the Secretary in accordance with this section.";

(3) in subsection (d)—

(A) in paragraph (1), by striking "and medium grain rice" and inserting "medium grain rice, and extra long staple cotton";

(B) by redesignating paragraphs (1) and (2) as subparagraphs (A) and (B), respectively, and indenting appropriately;

(C) in the matter preceding subparagraph (A) (as so redesignated), by striking "For purposes" and inserting the following:

"(1) IN GENERAL.—For purposes"; and

(D) by adding at the end the following:

"(2) UPLAND COTTON.—In the case of upland cotton, for any period when price quotations for Middling (M) 1$\frac{3}{32}$-inch cotton are available, the formula under paragraph (1)(A) shall be based on the average of the 3 lowest-priced growths that are quoted."; and

(4) in subsection (e)—

(A) in the subsection heading, by inserting "EXTRA LONG STAPLE COTTON," after "UPLAND COTTON,";

(B) in paragraph (2)—

(i) in the paragraph heading, by inserting "UPLAND" before "COTTON"; and

(ii) in subparagraph (B), in the matter preceding clause (i), by striking "2024" and inserting "2032";

(C) by redesignating paragraph (3) as paragraph (4); and

(D) by inserting after paragraph (2) the following:

"(3) EXTRA LONG STAPLE COTTON.—The prevailing world market price for extra long staple cotton determined under subsection (d)—

"(A) shall be adjusted to United States quality and location, with the adjustment to include the average costs to market the commodity, including average transportation costs, as determined by the Secretary; and

"(B) may be further adjusted, during the period beginning on the date of enactment of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress) and ending on July 31, 2032, if the Secretary determines the adjustment is necessary—

"(i) to minimize potential loan forfeitures;

"(ii) to minimize the accumulation of stocks of extra long staple cotton by the Federal Government;

"(iii) to ensure that extra long staple cotton produced in the United States can be marketed freely and competitively; and

"(iv) to ensure an appropriate transition between current-crop and forward-crop price quotations, except that the Secretary may use forward-crop price quotations prior to July 31 of a marketing year only if—

"(I) there are insufficient current-crop price quotations; and

"(II) the forward-crop price quotation is the lowest such quotation available.".

SEC. 10311. ECONOMIC ADJUSTMENT ASSISTANCE FOR TEXTILE MILLS.

Section 1207(c) of the Agricultural Act of 2014 (7 U.S.C. 9037(c)) is amended by striking paragraph (2) and inserting the following:

"(2) VALUE OF ASSISTANCE.—The value of the assistance provided under paragraph (1) shall be—

"(A) for the period beginning on August 1, 2013, and ending on July 31, 2025, 3 cents per pound; and

"(B) beginning on August 1, 2025, 5 cents per pound.".

SEC. 10312. SUGAR PROGRAM UPDATES.

(a) LOAN RATE MODIFICATIONS.—Section 156 of the Federal Agriculture Improvement and Reform Act of 1996 (7 U.S.C. 7272) is amended—

(1) in subsection (a)—

(A) in paragraph (4), by striking "and" at the end;

(B) in paragraph (5), by striking "2023 crop years." and inserting "2024 crop years; and"; and

(C) by adding at the end the following:

"(6) 24.00 cents per pound for raw cane sugar for each of the 2025 through 2031 crop years.";

(2) in subsection (b)—

(A) in paragraph (1), by striking "and" at the end;

(B) in paragraph (2), by striking "2023 crop years." and inserting "2024 crop years; and"; and

(C) by adding at the end the following:

"(3) a rate that is equal to 136.55 percent of the loan rate per pound of raw cane sugar under subsection (a)(6) for each of the 2025 through 2031 crop years."; and

(3) in subsection (i), by striking "2023" and inserting "2031".

(b) ADJUSTMENTS TO COMMODITY CREDIT CORPORATION STORAGE RATES.—Section 167 of the Federal Agriculture Improvement and Reform Act of 1996 (7 U.S.C. 7287) is amended—

(1) by striking subsection (a) and inserting the following:

"(a) IN GENERAL.—For the 2025 crop year and each subsequent crop year, the Commodity Credit Corporation shall establish rates for the storage of forfeited sugar in an amount that is not less than—

"(1) in the case of refined sugar, 34 cents per hundredweight per month; and

"(2) in the case of raw cane sugar, 27 cents per hundredweight per month."; and

(2) in subsection (b)—

(A) in the subsection heading, by striking "SUBSEQUENT" and inserting "PRIOR"; and

(B) by striking "and subsequent" and inserting "through 2024".

(c) MODERNIZING BEET SUGAR ALLOTMENTS.—

(1) SUGAR ESTIMATES.—Section 359b(a)(1) of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359bb(a)(1)) is amended by striking "2023" and inserting "2031".

(2) ALLOCATION TO PROCESSORS.—Section 359c(g)(2) of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359cc(g)(2)) is amended—

(A) by striking "In the case" and inserting the following:

"(A) IN GENERAL.—Except as provided in subparagraph (B), in the case"; and

(B) by adding at the end the following:

"(B) EXCEPTION.—If the Secretary makes an upward adjustment under paragraph (1)(A), in adjusting allocations among beet sugar processors, the Secretary shall give priority to beet sugar processors with available sugar.".

(3) TIMING OF REASSIGNMENT.—Section 359e(b)(2) of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359ee(b)(2)) is amended—

(A) by redesignating subparagraphs (A) through (C) as clauses (i) through (iii), respectively, and indenting appropriately;

(B) in the matter preceding clause (i) (as so redesignated), by striking "If the Secretary" and inserting the following:

"(A) IN GENERAL.—If the Secretary"; and

(C) by adding at the end the following:

"(B) TIMING.—In carrying out subparagraph (A), the Secretary shall—

"(i) make an initial determination based on the World Agricultural Supply and Demand Estimates approved by the World Agricultural Outlook Board for January that shall be applicable to the crop year for which allotments are required; and

"(ii) provide for an initial reassignment under subparagraph (A)(i) not later than 30 days after the date on which the World Agricultural Supply and Demand Estimates described in clause (i) is released.".

(d) REALLOCATIONS OF TARIFF-RATE QUOTA SHORTFALL.—Section 359k of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359kk) is amended by adding at the end the following:

"(c) REALLOCATION.—

"(1) INITIAL REALLOCATION.—Subject to paragraph (3), following the establishment of the tariff-rate quotas under subsection (a) for a quota year, the Secretary shall—

"(A) determine which countries do not intend to fulfill their allocation for the quota year; and

"(B) reallocate any forecasted shortfall in the fulfillment of the tariff-rate quotas as soon as practicable.

"(2) SUBSEQUENT REALLOCATION.—Subject to paragraph (3), not later than March 1 of a quota year, the Secretary shall reallocate any additional forecasted shortfall in the fulfillment of the tariff-rate quotas for raw cane sugar established under subsection (a)(1) for that quota year.

"(3) CESSATION OF EFFECTIVENESS.—Paragraphs (1) and (2) shall cease to be in effect if—

"(A) the Agreement Suspending the Countervailing Duty Investigation on Sugar from Mexico, signed December 19, 2014, is terminated; and

"(B) no countervailing duty order under subtitle A of title VII of the Tariff Act of 1930 (19 U.S.C. 1671 et seq.) is in effect with respect to sugar from Mexico.

"(d) REFINED SUGAR.—

"(1) DEFINITION OF DOMESTIC SUGAR INDUSTRY.—In this subsection, the term 'domestic sugar industry' means domestic—

"(A) sugar beet producers and processors;

"(B) producers and processors of sugar cane; and

"(C) refiners of raw cane sugar.

"(2) STUDY REQUIRED.—

"(A) IN GENERAL.—Not later than 180 days after the date of enactment of this subsection, the Secretary shall conduct a study on whether the establishment of additional terms and conditions with respect to refined sugar imports is necessary and appropriate.

"(B) ELEMENTS.—In conducting the study under subparagraph (A), the Secretary shall examine the following:

"(i) The need for—

"(I) defining 'refined sugar' as having a minimum polarization of 99.8 degrees or higher;

"(II) establishing a standard for color- or reflectance-based units for refined sugar such as those utilized by the International Commission of Uniform Methods of Sugar Analysis;

"(III) prescribing specifications for packaging type for refined sugar;

"(IV) prescribing specifications for transportation modes for refined sugar;

"(V) requiring evidence that sugar imported as refined sugar will not undergo further refining in the United States;

"(VI) prescribing appropriate terms and conditions to avoid unlawful sugar imports; and

"(VII) establishing other definitions, terms and conditions, or other requirements.

"(ii) The potential impact of modifications described in each of subclauses (I) through (VII) of clause (i) on the domestic sugar industry.

"(iii) Whether, based on the needs described in clause (i) and the impact described in clause (ii), the establishment of additional terms and conditions is appropriate.

"(C) CONSULTATION.—In conducting the study under subparagraph (A), the Secretary shall consult with representatives of the domestic sugar industry and users of refined sugar.

"(D) REPORT.—Not later than 1 year after the date of enactment of this subsection, the Secretary shall submit to the Committee on Agriculture of the House of Representatives and the Committee on Agriculture, Nutrition, and Forestry of the Senate a report that describes the findings of the study conducted under subparagraph (A).

"(3) ESTABLISHMENT OF ADDITIONAL TERMS AND CONDITIONS PERMITTED.—

"(A) IN GENERAL.—Based on the findings in the report submitted under paragraph (2)(D), and after providing notice to the Committee on Agriculture of the House of Representatives and the Committee on Agriculture, Nutrition, and Forestry of the Senate, the Secretary may issue regulations in accordance with subparagraph (B) to establish additional terms and conditions with respect to refined sugar imports that are necessary and appropriate.

"(B) PROMULGATION OF REGULATIONS.—The Secretary may issue regulations under subparagraph (A) if the regulations—

"(i) do not have an adverse impact on the domestic sugar industry; and

"(ii) are consistent with the requirements of this part, section 156 of the Federal Agriculture Improvement and Reform Act of 1996 (7 U.S.C. 7272), and obligations under international trade agreements that have been approved by Congress.".

(e) CLARIFICATION OF TARIFF-RATE QUOTA ADJUSTMENTS.—Section 359k(b)(1) of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359kk(b)(1)) is amended, in the matter preceding subparagraph (A), by striking "if there is an" and inserting "for the sole purpose of responding directly to an".

(f) PERIOD OF EFFECTIVENESS.—Section 359l(a) of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359ll(a)) is amended by striking "2023" and inserting "2031".

SEC. 10313. DAIRY POLICY UPDATES.

(a) DAIRY MARGIN COVERAGE PRODUCTION HISTORY.—

(1) DEFINITION.—Section 1401(8) of the Agricultural Act of 2014 (7 U.S.C. 9051(8)) is amended by striking "when the participating dairy operation first registers to participate in dairy margin coverage".

(2) PRODUCTION HISTORY OF PARTICIPATING DAIRY OPERATIONS.—Section 1405 of the Agricultural Act of 2014 (7 U.S.C. 9055) is amended by striking subsections (a) and (b) and inserting the following:

"(a) PRODUCTION HISTORY.—Except as provided in subsection (b), the production history of a dairy operation for dairy margin coverage is equal to the highest annual milk marketings of the participating dairy operation during any 1 of the 2021, 2022, or 2023 calendar years.

"(b) ELECTION BY NEW DAIRY OPERATIONS.—In the case of a participating dairy operation that has been in operation for less than a year, the participating dairy operation shall elect 1 of the following methods for the Secretary to determine the production history of the participating dairy operation:

"(1) The volume of the actual milk marketings for the months the participating dairy operation has been in operation extrapolated to a yearly amount.

"(2) An estimate of the actual milk marketings of the participating dairy operation based on the herd size of the participating dairy operation relative to the national rolling herd average data published by the Secretary.".

(b) DAIRY MARGIN COVERAGE PAYMENTS.—Section 1406(a)(1)(C) of the Agricultural Act of 2014 (7 U.S.C. 9056(a)(1)(C)) is amended by striking "5,000,000" each place it appears and inserting "6,000,000".

(c) PREMIUMS FOR DAIRY MARGINS.—

(1) TIER I.—Section 1407(b) of the Agricultural Act of 2014 (7 U.S.C. 9057(b)) is amended—

(A) in the subsection heading, by striking "5,000,000" and inserting "6,000,000"; and

(B) in paragraph (1), by striking "5,000,000" and inserting "6,000,000".

(2) TIER II.—Section 1407(c) of the Agricultural Act of 2014 (7 U.S.C. 9057(c)) is amended—

(A) in the subsection heading, by striking "5,000,000" and inserting "6,000,000"; and

(B) in paragraph (1), by striking "5,000,000" and inserting "6,000,000".

(3) PREMIUM DISCOUNTS.—Section 1407(g) of the Agricultural Act of 2014 (7 U.S.C. 9057(g)) is amended—

(A) in paragraph (1)—

(i) by striking "2019 through 2023" and inserting "2026 through 2031"; and

(ii) by striking "January 2019" and inserting "January 2026"; and

(B) in paragraph (2), by striking "2023" each place it appears and inserting "2031".

(d) DURATION.—Section 1409 of the Agricultural Act of 2014 (7 U.S.C. 9059) is amended by striking "2025" and inserting "2031".

SEC. 10314. IMPLEMENTATION.

Section 1614(c) of the Agricultural Act of 2014 (7 U.S.C. 9097(c)) is amended by adding at the end the following:

"(5) FURTHER FUNDING.—The Secretary shall make available to carry out subtitle C of title I of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress) and the amendments made by that subtitle $50,000,000, to remain available until expended, of which—

"(A) not less than $5,000,000 shall be used to carry out paragraphs (3) and (4) of subsection (b);

"(B) $3,000,000 shall be used for activities described in paragraph (3)(A);

"(C) $3,000,000 shall be used for activities described in paragraph (3)(B);

"(D) $9,000,000 shall be used—

"(i) to carry out mandatory surveys of dairy production cost and product yield information to be reported by manufacturers required to report under section 273 of the Agricultural Marketing Act of 1946 (7 U.S.C. 1637b), for all products processed in the same facility or facilities; and

"(ii) to publish the results of such surveys biennially; and

"(E) $1,000,000 shall be used to conduct the study under subsection (d) of section 359k of the Agricultural Adjustment Act of 1938 (7 U.S.C. 1359kk).".

Subtitle D—Disaster Assistance Programs

SEC. 10401. SUPPLEMENTAL AGRICULTURAL DISASTER ASSISTANCE.

(a) LIVESTOCK INDEMNITY PAYMENTS.—Section 1501(b) of the Agricultural Act of 2014 (7 U.S.C. 9081(b)) is amended—

(1) by striking paragraph (2) and inserting the following:

"(2) PAYMENT RATES.—

"(A) LOSSES DUE TO PREDATION.—Indemnity payments to an eligible producer on a farm under paragraph (1)(A) shall be made at a rate of 100 percent of the market value of the affected livestock on the applicable date, as determined by the Secretary.

"(B) LOSSES DUE TO ADVERSE WEATHER OR DISEASE.—Indemnity payments to an eligible producer on a farm under subparagraph (B) or (C) of paragraph (1) shall be made at a rate of 75 percent of the market value of the affected livestock on the applicable date, as determined by the Secretary.

"(C) DETERMINATION OF MARKET VALUE.—In determining the market value described in subparagraphs (A) and (B), the Secretary may consider the ability of eligible producers to document regional price premiums for affected livestock that exceed the national average market price for those livestock.

"(D) APPLICABLE DATE DEFINED.—In this paragraph, the term 'applicable date' means, with respect to livestock, as applicable—

"(i) the day before the date of death of the livestock; or

"(ii) the day before the date of the event that caused the harm to the livestock that resulted in a reduced sale price."; and

(2) by adding at the end the following:

"(5) ADDITIONAL PAYMENT FOR UNBORN LIVESTOCK.—

"(A) IN GENERAL.—In the case of unborn livestock death losses incurred on or after January 1, 2024, the Secretary shall make an additional payment to eligible producers on farms that have incurred such losses in excess of the normal mortality due to a condition specified in paragraph (1).

"(B) PAYMENT RATE.—Additional payments under subparagraph (A) shall be made at a rate—

"(i) determined by the Secretary; and

"(ii) less than or equal to 85 percent of the payment rate established with respect to the lowest weight class of the livestock, as determined by the Secretary, acting through the Administrator of the Farm Service Agency.

"(C) PAYMENT AMOUNT.—The amount of a payment to an eligible producer that has incurred unborn livestock death losses shall be equal to the payment rate determined under subparagraph (B) multiplied, in the case of livestock described in—

"(i) subparagraph (A), (B), or (F) of subsection (a)(4), by 1;

"(ii) subparagraph (D) of such subsection, by 2;

"(iii) subparagraph (E) of such subsection, by 12; and

"(iv) subparagraph (G) of such subsection, by the average number of birthed animals (for one gestation cycle) for the species of each such livestock, as determined by the Secretary.

"(D) UNBORN LIVESTOCK DEATH LOSSES DEFINED.—In this paragraph, the term 'unborn livestock death losses' means losses of any livestock described in subparagraph (A), (B), (D), (E), (F), or (G) of subsection (a)(4) that was gestating on the date of the death of the livestock.".

(b) LIVESTOCK FORAGE DISASTER PROGRAM.—Section 1501(c)(3)(D)(ii)(I) of the Agricultural Act of 2014 (7 U.S.C. 9081(c)(3)(D)(ii)(I)) is amended—

(1) by striking "1 monthly payment" and inserting "2 monthly payments"; and

(2) by striking "county for at least 8 consecutive" and inserting the following: "county for not less than— "

"(aa) 4 consecutive weeks during the normal grazing period for the county, as determined by the Secretary, shall be eligible to receive assistance under this paragraph in an amount equal to 1 monthly payment using the monthly payment rate determined under subparagraph (B); or

"(bb) 7 of the previous 8 consecutive".

(c) EMERGENCY ASSISTANCE FOR LIVESTOCK, HONEY BEES, AND FARM-RAISED FISH.—

(1) IN GENERAL.—Section 1501(d) of the Agricultural Act of 2014 (7 U.S.C. 9081(d)) is amended by adding at the end the following:

"(5) ASSISTANCE FOR LOSSES DUE TO BIRD DEPREDATION.—

"(A) DEFINITION OF FARM-RAISED FISH.—In this paragraph, the term 'farm-raised fish' means fish propagated and reared in a controlled fresh water environment.

"(B) PAYMENTS.—Eligible producers of farm-raised fish, including fish grown as food for human consumption, shall be eligible to receive payments under this subsection to aid in the reduction of losses due to piscivorous birds.

"(C) PAYMENT RATE.—

"(i) IN GENERAL.—The payment rate for payments under subparagraph (B) shall be determined by the Secretary, taking into account—

"(I) costs associated with the deterrence of piscivorous birds;

"(II) the value of lost fish and revenue due to bird depredation; and

"(III) costs associated with disease loss from bird depredation.

"(ii) MINIMUM RATE.—The payment rate for payments under subparagraph (B) shall be not less than $600 per acre of farm-raised fish.

"(D) PAYMENT AMOUNT.—The amount of a payment under subparagraph (B) shall be the product obtained by multiplying—

"(i) the applicable payment rate under subparagraph (C); and

"(ii) 85 percent of the total number of acres of farm-raised fish farms that the eligible producer has in production for the calendar year.".

(2) EMERGENCY ASSISTANCE FOR HONEYBEES.—In determining honeybee colony losses eligible for assistance under section 1501(d) of the Agricultural Act of 2014 (7 U.S.C. 9081(d)), the Secretary shall utilize a normal mortality rate of 15 percent.

(d) TREE ASSISTANCE PROGRAM.—Section 1501(e) of the Agricultural Act of 2014 (7 U.S.C. 9081(e)) is amended—

(1) in paragraph (2)(B), by striking "15 percent (adjusted for normal mortality)" and inserting "normal mortality"; and

(2) in paragraph (3)—

(A) in subparagraph (A)(i), by striking "15 percent mortality (adjusted for normal mortality)" and inserting "normal mortality"; and

(B) in subparagraph (B)—

(i) by striking "50" and inserting "65"; and

(ii) by striking "15 percent damage or mortality (adjusted for normal tree damage and mortality)" and inserting "normal tree damage or mortality".

Subtitle E—Crop Insurance

SEC. 10501. BEGINNING FARMER AND RANCHER BENEFIT.

(a) DEFINITIONS.—

(1) IN GENERAL.—Section 502(b)(3) of the Federal Crop Insurance Act (7 U.S.C. 1502(b)(3)) is amended by striking "5" and inserting "10".

(2) CONFORMING AMENDMENT.—Section 522(c)(7) of the Federal Crop Insurance Act (7 U.S.C. 1522(c)(7)) is amended by striking subparagraph (F).

(b) INCREASE IN ASSISTANCE.—Section 508(e) of the Federal Crop Insurance Act (7 U.S.C. 1508(e)) is amended by adding at the end the following:

"(9) ADDITIONAL SUPPORT.—

"(A) IN GENERAL.—In addition to any other provision of this subsection (except paragraph (2)(A)) regarding payment of a portion of premiums, a beginning farmer or rancher shall receive additional premium assistance that is the number of percentage points specified in subparagraph (B) greater than the premium assistance that would otherwise be available for the applicable policy, plan of insurance, and coverage level selected by the beginning farmer or rancher.

"(B) PERCENTAGE POINTS ADJUSTMENTS.—The percentage points referred to in subparagraph (A) are the following:

"(i) For each of the first and second reinsurance years that a beginning farmer or rancher participates as a beginning farmer or rancher in the applicable policy or plan of insurance, 5 percentage points.

"(ii) For the third reinsurance year that a beginning farmer or rancher participates as a beginning farmer or rancher in the applicable policy or plan of insurance, 3 percentage points.

"(iii) For the fourth reinsurance year that a beginning farmer or rancher participates as a beginning farmer or rancher in the applicable policy or plan of insurance, 1 percentage point.".

SEC. 10502. AREA-BASED CROP INSURANCE COVERAGE AND AFFORDABILITY.

(a) COVERAGE LEVEL.—Section 508(c)(4) of the Federal Crop Insurance Act (7 U.S.C. 1508(c)(4)) is amended—

(1) in subparagraph (A), by striking clause (ii) and inserting the following:

"(ii) may be purchased at any level not to exceed—

"(I) in the case of the individual yield or revenue coverage, 85 percent;

"(II) in the case of individual yield or revenue coverage aggregated across multiple commodities, 90 percent; and

"(III) in the case of area yield or revenue coverage (as determined by the Corporation), 95 percent."; and

(2) in subparagraph (C)—

(A) in clause (ii), by striking "14" and inserting "10"; and

(B) in clause (iii)(I), by striking "86" and inserting "90".

(b) PREMIUM SUBSIDY.—Section 508(e)(2)(H)(i) of the Federal Crop Insurance Act (7 U.S.C. 1508(e)(2)(H)(i)) is amended by striking "65" and inserting "80".

SEC. 10503. ADMINISTRATIVE AND OPERATING EXPENSE ADJUSTMENTS.

Section 508(k) of the Federal Crop Insurance Act (7 U.S.C. 1508(k)) is amended by adding at the end the following:

"(10) ADDITIONAL EXPENSES.—

"(A) IN GENERAL.—Beginning with the 2026 reinsurance year, and for each reinsurance year thereafter, in addition to the terms and conditions of the Standard Reinsurance Agreement, to cover additional expenses for loss adjustment procedures, the Corporation shall pay an additional administrative and operating expense subsidy to approved insurance providers for eligible contracts.

"(B) PAYMENT AMOUNT.—In the case of an eligible contract, the payment to an approved insurance provider required under subparagraph (A) shall be the amount equal to 6 percent of the net book premium.

"(C) DEFINITIONS.—In this paragraph:

"(i) ELIGIBLE CONTRACT.—The term 'eligible contract'—

"(I) means a crop insurance contract entered into by an approved insurance provider in an eligible State; and

"(II) does not include a contract for—

"(aa) catastrophic risk protection under subsection (b);

"(bb) an area-based plan of insurance or similar plan of insurance, as determined by the Corporation; or

"(cc) a policy under which an approved insurance provider does not incur loss adjustment expenses, as determined by the Corporation.

"(ii) ELIGIBLE STATE.—The term 'eligible State' means a State in which, with respect to an insurance year, the loss ratio for eligible contracts is greater than 120 percent of the total net book premium written by all approved insurance providers.

"(11) SPECIALTY CROPS.—

"(A) MINIMUM REIMBURSEMENT.—Beginning with the 2026 reinsurance year, and for each reinsurance year thereafter, the rate of reimbursement to approved insurance providers and agents for administrative and operating expenses with respect to crop insurance contracts covering agricultural commodities described in section 101 of the Specialty Crops Competitiveness Act of 2004 (7 U.S.C. 1621 note; Public Law 108–465) shall be equal to or greater than the percentage that is the greater of the following:

"(i) 17 percent of the premium used to define loss ratio.

"(ii) The percent of the premium used to define loss ratio that is otherwise applicable for the reinsurance year under the terms of the Standard Reinsurance Agreement in effect for the reinsurance year.

"(B) OTHER CONTRACTS.—In carrying out subparagraph (A), the Corporation shall not reduce, with respect to any reinsurance year, the amount or the rate of reimbursement to approved insurance providers and agents under the Standard Reinsurance Agreement described in clause (ii) of such subparagraph for administrative and operating expenses with respect to contracts covering agricultural commodities that are not subject to such subparagraph.

"(C) ADMINISTRATION.—The requirements of this paragraph and the adjustments made pursuant to this paragraph shall not be considered a renegotiation under paragraph (8)(A).

"(12) A&O INFLATION ADJUSTMENT.—

"(A) IN GENERAL.—Subject to subparagraph (B), beginning with the 2026 reinsurance year, and for each reinsurance year thereafter, the Corporation shall increase the total administrative and operating expense reimbursements otherwise required under the Standard Reinsurance Agreement in effect for the reinsurance year in order to account for inflation, in a manner consistent with the increases provided with respect to the 2011 through 2015 reinsurance years under the enclosure included in Risk Management Agency Bulletin numbered MGR–10–007 and dated June 30, 2010.

"(B) SPECIAL RULE FOR 2026 REINSURANCE YEAR.—The increase under subparagraph (A) for the 2026 reinsurance year shall not exceed the percentage change for the preceding reinsurance year included in the Consumer Price Index for All Urban Consumers published by the Bureau of Labor Statistics of the Department of Labor.

"(C) ADMINISTRATION.—An increase under subparagraph (A)—

"(i) shall apply with respect to all contracts covering agricultural commodities that were subject to an increase during the period of the 2011 through 2015 reinsurance years under the enclosure referred to in that subparagraph; and

"(ii) shall not be considered a renegotiation under paragraph (8)(A).".

SEC. 10504. PREMIUM SUPPORT.

Section 508(e)(2) of the Federal Crop Insurance Act (7 U.S.C. 1508(e)(2)) is amended—

(1) in subparagraph (C)(i), by striking "64" and inserting "69";

(2) in subparagraph (D)(i), by striking "59" and inserting "64";

(3) in subparagraph (E)(i), by striking "55" and inserting "60";

(4) in subparagraph (F)(i), by striking "48" and inserting "51"; and

(5) in subparagraph (G)(i), by striking "38" and inserting "41".

SEC. 10505. PROGRAM COMPLIANCE AND INTEGRITY.

Section 515(l)(2) of the Federal Crop Insurance Act (7 U.S.C. 1515(l)(2)) is amended by striking "than" and all that follows through the period at the end and inserting the following: "than—

"(A) $4,000,000 for each of fiscal years 2009 through 2025; and

"(B) $6,000,000 for fiscal year 2026 and each subsequent fiscal year.".

SEC. 10506. REVIEWS, COMPLIANCE, AND INTEGRITY.

Section 516(b)(2)(C)(i) of the Federal Crop Insurance Act (7 U.S.C. 1516(b)(2)(C)(i)) is amended, in the matter preceding subclause (I), by striking "for each fiscal year" and inserting "for each of fiscal years 2014 through 2025 and $10,000,000 for fiscal year 2026 and each fiscal year thereafter".

SEC. 10507. POULTRY INSURANCE PILOT PROGRAM.

Section 523 of the Federal Crop Insurance Act (7 U.S.C. 1523) is amended by adding at the end the following:

"(j) POULTRY INSURANCE PILOT PROGRAM.—

"(1) IN GENERAL.—Notwithstanding subsection (a)(2), the Corporation shall establish a pilot program under which contract poultry growers, including growers of broilers and laying hens, may elect to receive index-based insurance from extreme weather-related risk resulting in increased utility costs (including costs of natural gas, propane, electricity, water, and other appropriate costs, as determined by the Corporation) associated with poultry production.

"(2) STAKEHOLDER ENGAGEMENT.—The Corporation shall engage with poultry industry stakeholders in establishing the pilot program under paragraph (1).

"(3) LOCATION.—The pilot program established under paragraph (1) shall be conducted in a sufficient number of counties to provide a comprehensive evaluation of the feasibility, effectiveness, and demand among producers in the top poultry producing States, as determined by the Corporation.

"(4) APPROVAL OF POLICY OR PLAN.—Notwithstanding section 508(l), the Board shall approve a policy or plan of insurance based on the pilot program under paragraph (1)—

"(A) in accordance with section 508(h); and

"(B) not later than 2 years after the date of enactment of this subsection.".

Subtitle F—Additional Investments in Rural America

SEC. 10601. CONSERVATION.

(a) IN GENERAL.—Section 1241(a) of the Food Security Act of 1985 (16 U.S.C. 3841(a)) is amended—

(1) in paragraph (2), by striking subparagraphs (A) through (F) and inserting the following:

"(A) $625,000,000 for fiscal year 2026;

"(B) $650,000,000 for fiscal year 2027;

"(C) $675,000,000 for fiscal year 2028;

"(D) $700,000,000 for fiscal year 2029;

"(E) $700,000,000 for fiscal year 2030; and

"(F) $700,000,000 for fiscal year 2031."; and

(2) in paragraph (3)—

(A) in subparagraph (A), by striking clauses (i) through (v) and inserting the following:

"(i) $2,655,000,000 for fiscal year 2026;

"(ii) $2,855,000,000 for fiscal year 2027;

"(iii) $3,255,000,000 for fiscal year 2028;

"(iv) $3,255,000,000 for fiscal year 2029;

"(v) $3,255,000,000 for fiscal year 2030; and

"(vi) $3,255,000,000 for fiscal year 2031; and"; and

(B) in subparagraph (B), by striking clauses (i) through (v) and inserting the following:

"(i) $1,300,000,000 for fiscal year 2026;

"(ii) $1,325,000,000 for fiscal year 2027;

"(iii) $1,350,000,000 for fiscal year 2028;

"(iv) $1,375,000,000 for fiscal year 2029;

"(v) $1,375,000,000 for fiscal year 2030; and

"(vi) $1,375,000,000 for fiscal year 2031.".

(b) REGIONAL CONSERVATION PARTNERSHIP PROGRAM.—Section 1271D of the Food Security Act of 1985 (16 U.S.C. 3871d) is amended by striking subsection (a) and inserting the following:

"(a) AVAILABILITY OF FUNDING.—Of the funds of the Commodity Credit Corporation, the Secretary shall use to carry out the program, to the maximum extent practicable—

"(1) $425,000,000 for fiscal year 2026;
"(2) $450,000,000 for fiscal year 2027;
"(3) $450,000,000 for fiscal year 2028;
"(4) $450,000,000 for fiscal year 2029;
"(5) $450,000,000 for fiscal year 2030; and
"(6) $450,000,000 for fiscal year 2031.".

(c) GRASSROOTS SOURCE WATER PROTECTION PROGRAM.—Section 1240O(b) of the Food Security Act of 1985 (16 U.S.C. 3839bb–2(b)) is amended—

(1) in paragraph (1), by striking "2023" and inserting "2031"; and

(2) in paragraph (3)—

(A) in subparagraph (A), by striking "and" at the end;

(B) in subparagraph (B), by striking the period at the end and inserting "; and"; and

(C) by adding at the end the following:

"(C) $1,000,000 beginning in fiscal year 2026, to remain available until expended.".

(d) VOLUNTARY PUBLIC ACCESS AND HABITAT INCENTIVE PROGRAM.—Section 1240R(f)(1) of the Food Security Act of 1985 (16 U.S.C. 3839bb–5(f)(1)) is amended—

(1) by striking "2023, and" and inserting "2023,"; and

(2) by inserting ", and $70,000,000 for the period of fiscal years 2025 through 2031" before the period at the end.

(e) WATERSHED PROTECTION AND FLOOD PREVENTION.—Section 15 of the Watershed Protection and Flood Prevention Act (16 U.S.C. 1012a) is amended by striking "$50,000,000 for fiscal year 2019 and each fiscal year thereafter" and inserting "$150,000,000 for fiscal year 2026 and each fiscal year thereafter, to remain available until expended".

(f) FERAL SWINE ERADICATION AND CONTROL PILOT PROGRAM.—Section 2408(g)(1) of the Agriculture Improvement Act of 2018 (7 U.S.C. 8351 note; Public Law 115–334) is amended—

(1) by striking "2023 and" and inserting "2023,"; and

(2) by inserting ", and $105,000,000 for the period of fiscal years 2025 through 2031" before the period at the end.

(g) RESCISSION.—The unobligated balances of amounts appropriated by section 21001(a) of Public Law 117–169 (136 Stat. 2015) are rescinded.

SEC. 10602. SUPPLEMENTAL AGRICULTURAL TRADE PROMOTION PROGRAM.

(a) IN GENERAL.—The Secretary of Agriculture shall carry out a program to encourage the accessibility, development, maintenance, and expansion of commercial export markets for United States agricultural commodities.

(b) FUNDING.—Of the funds of the Commodity Credit Corporation, the Secretary of Agriculture shall make available to carry out this section $285,000,000 for fiscal year 2027 and each fiscal year thereafter.

SEC. 10603. NUTRITION.

Section 203D(d)(5) of the Emergency Food Assistance Act of 1983 (7 U.S.C. 7507(d)(5)) is amended by striking "2024" and inserting "2031".

SEC. 10604. RESEARCH.

(a) URBAN, INDOOR, AND OTHER EMERGING AGRICULTURAL PRODUCTION RESEARCH, EDUCATION, AND EXTENSION INITIATIVE.—Section 1672E(d)(1)(B) of the Food, Agriculture, Conservation, and Trade Act of 1990 (7 U.S.C. 5925g(d)(1)(B)) is amended by striking "fiscal year 2024, to remain available until expended" and inserting "each of fiscal years 2024 through 2031".

(b) FOUNDATION FOR FOOD AND AGRICULTURE RESEARCH.—Section 7601(g)(1)(A) of the Agricultural Act of 2014 (7 U.S.C. 5939(g)(1)(A)) is amended by adding at the end the following:

"(iv) FURTHER FUNDING.—Not later than 30 days after the date of enactment of this clause, of the funds of the Commodity Credit Corporation, the Secretary shall transfer to the Foundation to carry out this section $37,000,000, to remain available until expended.".

(c) SCHOLARSHIPS FOR STUDENTS AT 1890 INSTITUTIONS.—Section 1446(b)(1) of the National Agricultural Research, Extension, and Teaching Policy Act of 1977 (7 U.S.C. 3222a(b)(1)) is amended by adding at the end the following:

"(C) FURTHER FUNDING.—Of the funds of the Commodity Credit Corporation, the Secretary shall make available to carry out this section $60,000,000 for fiscal year 2026, to remain available until expended.".

(d) ASSISTIVE TECHNOLOGY PROGRAM FOR FARMERS WITH DISABILITIES.—Section 1680 of the Food, Agriculture, Conservation, and Trade Act of 1990 (7 U.S.C. 5933) is amended—

(1) in subsection (c)(2), by inserting "and subsection (d)" after "paragraph (1)"; and

(2) by adding at the end the following:

"(d) MANDATORY FUNDING.—Subject to subsection (c)(2), of the funds of the Commodity Credit Corporation, the Secretary shall use to carry out this section $8,000,000 for fiscal year 2026, to remain available until expended.".

(e) SPECIALTY CROP RESEARCH INITIATIVE.—Section 412(k)(1)(B) of the Agricultural Research, Extension, and Education Reform Act of 1998 (7 U.S.C. 7632(k)(1)(B)) is amended by striking "section $80,000,000 for fiscal year 2014" and inserting the following: "section—

"(i) $80,000,000 for each of fiscal years 2014 through 2025; and

"(ii) $175,000,000 for fiscal year 2026".

(f) RESEARCH FACILITIES ACT.—Section 6 of the Research Facilities Act (7 U.S.C. 390d) is amended—

(1) in subsection (c), by striking "subsection (a)" and inserting "subsections (a) and (e)"; and

(2) by adding at the end the following:

"(e) MANDATORY FUNDING.—Subject to subsections (b), (c), and (d), of the funds of the Commodity Credit Corporation, the Secretary shall make available to carry out the competitive grant program under section 4 $125,000,000 for fiscal year 2026 and each fiscal year thereafter.".

SEC. 10605. ENERGY.

Section 9005(g)(1)(F) of the Farm Security and Rural Investment Act of 2002 (7 U.S.C. 8105(g)(1)(F)) is amended by striking "2024" and inserting "2031".

SEC. 10606. HORTICULTURE.

(a) PLANT PEST AND DISEASE MANAGEMENT AND DISASTER PREVENTION.—Section 420(f) of the Plant Protection Act (7 U.S.C. 7721(f)) is amended—

(1) in paragraph (5), by striking "and" at the end;

(2) by redesignating paragraph (6) as paragraph (7);

(3) by inserting after paragraph (5) the following:

"(6) $75,000,000 for each of fiscal years 2018 through 2025; and"; and

(4) in paragraph (7) (as so redesignated), by striking "$75,000,000 for fiscal year 2018" and inserting "$90,000,000 for fiscal year 2026".

(b) SPECIALTY CROP BLOCK GRANTS.—Section 101(l)(1) of the Specialty Crops Competitiveness Act of 2004 (7 U.S.C. 1621 note; Public Law 108–465) is amended—

(1) in subparagraph (D), by striking "and" at the end;

(2) by redesignating subparagraph (E) as subparagraph (F);

(3) by inserting after subparagraph (D) the following:

"(E) $85,000,000 for each of fiscal years 2018 through 2025; and"; and

(4) in subparagraph (F) (as so redesignated), by striking "$85,000,000 for fiscal year 2018" and inserting "$100,000,000 for fiscal year 2026".

(c) ORGANIC PRODUCTION AND MARKET DATA INITIATIVE.—Section 7407(d)(1) of the Farm Security and Rural Investment Act of 2002 (7 U.S.C. 5925c(d)(1)) is amended—

(1) in subparagraph (B), by striking "and" at the end;

(2) in subparagraph (C), by striking the period at the end and inserting "; and"; and

(3) by adding at the end the following:

"(D) $10,000,000 for the period of fiscal years 2026 through 2031.".

(d) MODERNIZATION AND IMPROVEMENT OF INTERNATIONAL TRADE TECHNOLOGY SYSTEMS AND DATA COLLECTION.—Section 2123(c)(4) of the Organic Foods Production Act of 1990 (7 U.S.C. 6522(c)(4)) is amended, in the matter preceding subparagraph (A), by striking "and $1,000,000 for fiscal year 2024" and inserting ", $1,000,000 for fiscal years 2024 and 2025, and $5,000,000 for fiscal year 2026".

(e) NATIONAL ORGANIC CERTIFICATION COST-SHARE PROGRAM.—Section 10606(d)(1)(C) of the Farm Security and Rural Investment Act of 2002 (7 U.S.C. 6523(d)(1)(C)) is amended by striking "2024" and inserting "2031".

(f) MULTIPLE CROP AND PESTICIDE USE SURVEY.—Section 10109(c) of the Agriculture Improvement Act of 2018 (Public Law 115–334; 132 Stat. 4907) is amended by adding at the end the following:

"(3) FURTHER MANDATORY FUNDING.—Of the funds of the Commodity Credit Corporation, the Secretary shall use to carry out this section $5,000,000 for fiscal year 2026, to remain available until expended.".

SEC. 10607. MISCELLANEOUS.

(a) ANIMAL DISEASE PREVENTION AND MANAGEMENT.—Section 10409A(d)(1) of the Animal Health Protection Act (7 U.S.C. 8308a(d)(1)) is amended—

(1) in subparagraph (B)—

(A) in the heading, by striking "SUBSEQUENT FISCAL YEARS" and inserting "FISCAL YEARS 2023 THROUGH 2025"; and

(B) by striking "fiscal year 2023 and each fiscal year thereafter" and inserting "each of fiscal years 2023 through 2025"; and

(2) by adding at the end the following:

"(C) FISCAL YEARS 2026 THROUGH 2030.—Of the funds of the Commodity Credit Corporation, the Secretary shall make available to carry out this section $233,000,000 for each of fiscal years 2026 through 2030, of which—

"(i) not less than $10,000,000 shall be made available for each such fiscal year to carry out subsection (a);

"(ii) not less than $70,000,000 shall be made available for each such fiscal year to carry out subsection (b); and

"(iii) not less than $153,000,000 shall be made available for each such fiscal year to carry out subsection (c).

"(D) SUBSEQUENT FISCAL YEARS.—Of the funds of the Commodity Credit Corporation, the Secretary shall make available to carry out this section $75,000,000 for fiscal year 2031 and each fiscal year thereafter, of which not less than $45,000,000 shall be made available for each of those fiscal years to carry out subsection (b).".

(b) SHEEP PRODUCTION AND MARKETING GRANT PROGRAM.—Section 209(c) of the Agricultural Marketing Act of 1946 (7 U.S.C. 1627a(c)) is amended—

(1) by striking "2019, and" and inserting "2019,"; and

(2) by inserting "and $3,000,000 for fiscal year 2026," after "fiscal year 2024,"

(c) PIMA AGRICULTURE COTTON TRUST FUND.—Section 12314 of the Agricultural Act of 2014 (7 U.S.C. 2101 note; Public Law 113–79) is amended—

(1) in subsection (b), in the matter preceding paragraph (1), by striking "2024" and inserting "2031"; and

(2) in subsection (h), by striking "2024"and inserting "2031".

(d) AGRICULTURE WOOL APPAREL MANUFACTURERS TRUST FUND.—Section 12315 of the Agricultural Act of 2014 (7 U.S.C. 7101 note; Public Law 113–79) is amended by striking "2024" each place it appears and inserting "2031".

(e) WOOL RESEARCH AND PROMOTION.—Section 12316(a) of the Agricultural Act of 2014 (7 U.S.C. 7101 note; Public Law 113–79) is amended by striking "2024" and inserting "2031".

(f) EMERGENCY CITRUS DISEASE RESEARCH AND DEVELOPMENT TRUST FUND.—Section 12605(d) of the Agriculture Improvement Act of 2018 (7 U.S.C. 7632 note; Public Law 115–334) is amended by striking "2024" and inserting "2031".

TITLE II—COMMITTEE ON ARMED SERVICES

SEC. 20001. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR IMPROVING THE QUALITY OF LIFE FOR MILITARY PERSONNEL.

(a) APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $230,480,000 for restoration and modernization costs under the Marine Corps Barracks 2030 initiative;

(2) $119,000,000 for base operating support costs under the Marine Corps;

(3) $1,000,000,000 for Army, Navy, Air Force, and Space Force sustainment, restoration, and modernization of military unaccompanied housing;

(4) $2,000,000,000 for the Defense Health Program;

(5) $2,900,000,000 to supplement the basic allowance for housing payable to members of the Army, Air Force, Navy, Marine Corps, and Space Force , notwithstanding section 403 of title 37, United States Code;

(6) $50,000,000 for bonuses, special pays, and incentive pays for members of the Army, Air Force, Navy, Marine Corps, and Space Force pursuant to titles 10 and 37, United States Code;

(7) $10,000,000 for the Defense Activity for Non-Traditional Education Support's Online Academic Skills Course program for members of the Army, Air Force, Navy, Marine Corps, and Space Force;

(8) $100,000,000 for tuition assistance for members of the Army, Air Force, Navy, Marine Corps, and Space Force pursuant to title 10, United States Code;

(9) $100,000,000 for child care fee assistance for members of the Army, Air Force, Navy, Marine Corps, and Space Force under part II of chapter 88 of title 10, United States Code;

(10) $590,000,000 to increase the Temporary Lodging Expense Allowance under chapter 8 of title 37, United States Code, to 21 days;

(11) $100,000,000 for Department of Defense Impact Aid payments to local educational agencies under section 2008 of title 10, United States Code;

(12) $10,000,000 for military spouse professional licensure under section 1784 of title 10, United States Code;

(13) $6,000,000 for Armed Forces Retirement Home facilities;

(14) $100,000,000 for the Defense Community Infrastructure Program;

(15) $100,000,000 for Defense Advanced Research Projects Agency (DARPA) casualty care research; and

(16) $62,000,000 for modernization of Department of Defense childcare center staffing.

(b) TEMPORARY INCREASE IN PERCENTAGE OF VALUE OF AUTHORIZED INVESTMENT IN CERTAIN PRIVATIZED MILITARY HOUSING PROJECTS.—

(1) IN GENERAL.—During the period beginning on the date of the enactment of this section and ending on September 30, 2029, the Secretary concerned shall apply—

(A) paragraph (1) of subsection (c) of section 2875 of title 10, United States Code, by substituting "60 percent" for "33 ⅓ percent"; and

(B) paragraph (2) of such subsection by substituting "60 percent" for "45 percent".

(2) SECRETARY CONCERNED DEFINED.—In this subsection, the term "Secretary concerned" has the meaning given such term in section 101 of title 10, United States Code.

(c) TEMPORARY AUTHORITY FOR ACQUISITION OR CONSTRUCTION OF PRIVATIZED MILITARY UNACCOMPANIED HOUSING.—Section 2881a of title 10, United States Code, is amended—

(1) by striking the heading and inserting "**Temporary authority for acquisition or construction of privatized military unaccompanied housing**";

(2) by striking "Secretary of the Navy" each place it appears and inserting "Secretary concerned";

(3) by striking "under the pilot projects" each place it appears and inserting "pursuant to this section";

(4) in subsection (a)—

(A) by striking the heading and inserting "IN GENERAL"; and

(B) by striking "carry out not more than three pilot projects under the authority of this section or another provision of this subchapter to use the private sector" and inserting "use the authority under this subchapter to enter into contracts with appropriate private sector entities";

(5) in subsection (c), by striking "privatized housing" and inserting "privatized housing units";

(6) by redesignating subsection (f) as subsection (e); and

(7) in subsection (e) (as so redesignated)—

(A) by striking "under the pilot programs" and inserting "under this section"; and

(B) by striking "September 30, 2009" and inserting "September 30, 2029".

SEC. 20002. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR SHIPBUILDING.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $250,000,000 for the expansion of accelerated Training in Defense Manufacturing program;

(2) $250,000,000 for United States production of turbine generators for shipbuilding industrial base;

(3) $450,000,000 for United States additive manufacturing for wire production and machining capacity for shipbuilding industrial base;

(4) $492,000,000 for next-generation shipbuilding techniques;

(5) $85,000,000 for United States-made steel plate for shipbuilding industrial base;

(6) $50,000,000 for machining capacity for naval propellers for shipbuilding industrial base;

(7) $110,000,000 for rolled steel and fabrication facility for shipbuilding industrial base;

(8) $400,000,000 for expansion of collaborative campus for naval shipbuilding;

(9) $450,000,000 for application of autonomy and artificial intelligence to naval shipbuilding;

(10) $500,000,000 for the adoption of advanced manufacturing techniques in the shipbuilding industrial base;

(11) $500,000,000 for additional dry-dock capability;

(12) $50,000,000 for the expansion of cold spray repair technologies;

(13) $450,000,000 for additional maritime industrial workforce development programs;

(14) $750,000,000 for additional supplier development across the naval shipbuilding industrial base;

(15) $250,000,000 for additional advanced manufacturing processes across the naval shipbuilding industrial base;

(16) $4,600,000,000 for a second Virginia-class submarine in fiscal year 2026;

(17) $5,400,000,000 for two additional Guided Missile Destroyer (DDG) ships;

(18) $160,000,000 for advanced procurement for Landing Ship Medium;

(19) $1,803,941,000 for procurement of Landing Ship Medium;

(20) $295,000,000 for development of a second Landing Craft Utility shipyard and production of additional Landing Craft Utility;

(21) $100,000,000 for advanced procurement for light replenishment oiler program;

(22) $600,000,000 for the lease or purchase of new ships through the National Defense Sealift Fund;

(23) $2,725,000,000 for the procurement of T-AO oilers;

(24) $500,000,000 for cost-to-complete for rescue and salvage ships;

(25) $300,000,000 for production of ship-to-shore connectors;

(26) $1,470,000,000 for the implementation of a multi-ship amphibious warship contract;

(27) $80,000,000 for accelerated development of vertical launch system reloading at sea;

(28) $250,000,000 for expansion of Navy corrosion control programs;

(29) $159,000,000 for leasing of ships for Marine Corps operations;

(30) $1,534,000,000 for expansion of small unmanned surface vessel production;

(31) $2,100,000,000 for development, procurement, and integration of purpose-built medium unmanned surface vessels;

(32) $1,300,000,000 for expansion of unmanned underwater vehicle production;

(33) $188,360,000 for the development and testing of maritime robotic autonomous systems and enabling technologies;

(34) $174,000,000 for the development of a Test Resource Management Center robotic autonomous systems proving ground;

(35) $250,000,000 for the development, production, and integration of wave-powered unmanned underwater vehicles; and

(36) $150,000,000 for retention of inactive reserve fleet ships.

SEC. 20003. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR INTEGRATED AIR AND MISSILE DEFENSE.

(a) NEXT GENERATION MISSILE DEFENSE TECHNOLOGIES.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $250,000,000 for development and testing of directed energy capabilities by the Under Secretary for Research and Engineering;

(2) $500,000,000 for national security space launch infrastructure;

(3) $2,000,000,000 for air moving target indicator military satellites;

(4) $400,000,000 for expansion of Multi-Service Advanced Capability Hypersonic Test Bed program;

(5) $5,600,000,000 for development of space-based and boost phase intercept capabilities;

(6) $7,200,000,000 for the development, procurement, and integration of military space-based sensors; and

(7) $2,550,000,000 for the development, procurement, and integration of military missile defense capabilities.

(b) LAYERED HOMELAND DEFENSE.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $2,200,000,000 for acceleration of hypersonic defense systems;

(2) $800,000,000 for accelerated development and deployment of next-generation intercontinental ballistic missile defense systems;

(3) $408,000,000 for Army space and strategic missile test range infrastructure restoration and modernization in the United States Indo-Pacific Command area of operations west of the international dateline;

(4) $1,975,000,000 for improved ground-based missile defense radars; and

(5) $530,000,000 for the design and construction of Missile Defense Agency missile instrumentation range safety ship.

SEC. 20004. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR MUNITIONS AND DEFENSE SUPPLY CHAIN RESILIENCY.

(a) APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $400,000,000 for the development, production, and integration of Navy and Air Force long-range anti-ship missiles;

(2) $380,000,000 for production capacity expansion for Navy and Air Force long-range anti-ship missiles;

(3) $490,000,000 for the development, production, and integration of Navy and Air Force long-range air-to-surface missiles;

(4) $94,000,000 for the development, production, and integration of alternative Navy and Air Force long-range air-to-surface missiles;

(5) $630,000,000 for the development, production, and integration of long-range Navy air defense and anti-ship missiles;

(6) $688,000,000 for the development, production, and integration of long-range multi-service cruise missiles;

(7) $250,000,000 for production capacity expansion and supplier base strengthening of long-range multi-service cruise missiles;

(8) $70,000,000 for the development, production, and integration of short-range Navy and Marine Corps anti-ship missiles;

(9) $100,000,000 for the development of an anti-ship seeker for short-range Army ballistic missiles;

(10) $175,000,000 for production capacity expansion for next-generation Army medium-range ballistic missiles;

(11) $50,000,000 for the mitigation of diminishing manufacturing sources for medium-range air-to-air missiles;

(12) $250,000,000 for the procurement of medium-range air-to-air missiles;

(13) $225,000,000 for the expansion of production capacity for medium-range air-to-air missiles;

(14) $50,000,000 for the development of second sources for components of short-range air-to-air missiles;

(15) $325,000,000 for production capacity improvements for air-launched anti-radiation missiles;

(16) $50,000,000 for the accelerated development of Army next-generation medium-range anti-ship ballistic missiles;

(17) $114,000,000 for the production of Army next-generation medium-range ballistic missiles;

(18) $300,000,000 for the production of Army medium-range ballistic missiles;

(19) $85,000,000 for the accelerated development of Army long-range ballistic missiles;

(20) $400,000,000 for the production of heavyweight torpedoes;

(21) $200,000,000 for the development, procurement, and integration of mass-producible autonomous underwater munitions;

(22) $70,000,000 for the improvement of heavyweight torpedo maintenance activities;

(23) $200,000,000 for the production of lightweight torpedoes;

(24) $500,000,000 for the development, procurement, and integration of maritime mines;

(25) $50,000,000 for the development, procurement, and integration of new underwater explosives;

(26) $55,000,000 for the development, procurement, and integration of lightweight multi-mission torpedoes;

(27) $80,000,000 for the production of sonobuoys;

(28) $150,000,000 for the development, procurement, and integration of air-delivered long-range maritime mines;

(29) $61,000,000 for the acceleration of Navy expeditionary loitering munitions deployment;

(30) $50,000,000 for the acceleration of one-way attack unmanned aerial systems with advanced autonomy;

(31) $1,000,000,000 for the expansion of the one-way attack unmanned aerial systems industrial base;

(32) $200,000,000 for investments in solid rocket motor industrial base through the Industrial Base Fund established under section 4817 of title 10, United States Code;

(33) $400,000,000 for investments in the emerging solid rocket motor industrial base through the Industrial Base Fund established under section 4817 of title 10, United States Code;

(34) $42,000,000 for investments in second sources for large-diameter solid rocket motors for hypersonic missiles;

(35) $1,000,000,000 for the creation of next-generation automated munitions production factories;

(36) $170,000,000 for the development of advanced radar depot for repair, testing, and production of radar and electronic warfare systems;

(37) $25,000,000 for the expansion of the Department of Defense industrial base policy analysis workforce;

(38) $30,300,000 for the repair of Army missiles;

(39) $100,000,000 for the production of small and medium ammunition;

(40) $2,000,000,000 for additional activities to improve the United States stockpile of critical minerals through the National Defense Stockpile Transaction Fund, authorized by subchapter III of chapter 5 of title 50, United States Code;

(41) $10,000,000 for the expansion of the Department of Defense armaments cooperation workforce;

(42) $500,000,000 for the expansion of the Defense Exportability Features program;

(43) $350,000,000 for production of Navy long-range air and missile defense interceptors;

(44) $93,000,000 for replacement of Navy long-range air and missile defense interceptors;

(45) $100,000,000 for development of a second solid rocket motor source for Navy air defense and anti ship missiles;

(46) $65,000,000 for expansion of production capacity of Missile Defense Agency long-range anti-ballistic missiles;

(47) $225,000,000 for expansion of production capacity for Navy air defense and anti-ship missiles;

(48) $103,300,000 for expansion of depot level maintenance facility for Navy long-range air and missile defense interceptors;

(49) $18,000,000 for creation of domestic source for guidance section of Navy short-range air defense missiles;

(50) $65,000,000 for integration of Army medium-range air and missile defense interceptor with Navy ships;

(51) $176,100,000 for production of Army long-range movable missile defense radar;

(52) $167,000,000 for accelerated fielding of Army short-range gun-based air and missile defense system;

(53) $40,000,000 for development of low-cost alternatives to air and missile defense interceptors;

(54) $50,000,000 for acceleration of Army next-generation shoulder-fired air defense system;

(55) $91,000,000 for production of Army next-generation shoulder-fired air defense system;

(56) $500,000,000 for development, production, and integration of counter-unmanned aerial systems programs;

(57) $350,000,000 for development, production, and integration of non-kinetic counter-unmanned aerial systems programs;

(58) $250,000,000 for development, production, and integration of land-based counter-unmanned aerial systems programs;

(59) $200,000,000 for development, production, and integration of ship-based counter-unmanned aerial systems programs;

(60) $400,000,000 for acceleration of hypersonic strike programs;

(61) $167,000,000 for procurement of additional launchers for Army medium-range air and missile defense interceptors;

(62) $500,000,000 for expansion of defense advanced manufacturing techniques;

(63) $1,000,000 for establishment of the Joint Energetics Transition Office;

(64) $200,000,000 for acceleration of Army medium-range air and missile defense interceptors;

(65) $150,000,000 for additive manufacturing for propellant;

(66) $250,000,000 for expansion and acceleration of penetrating munitions production; and

(67) $50,000,000 for development, procurement, and integration of precision extended-range artillery.

(b) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $3,300,000,000 for grants and purchase commitments made pursuant to the Industrial Base Fund established under section 4817 of title 10, United States Code.

(c) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $5,000,000,000 for investments in critical minerals supply chains made pursuant to the Industrial Base Fund established under section 4817 of title 10, United States Code.

(d) APPROPRIATIONS.—In addition to amounts otherwise available, there is appropriated to the Secretary of Defense, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $500,000,000 to the "Department of Defense Credit Program Account" to carry out the capital assistance program, including loans, loan guarantees, and technical assistance, established under section 149(e) of title 10, United States Code, for critical minerals and related industries and projects, including related Covered Technology Categories: *Provided*, That—

(1) such amounts are available to subsidize gross obligations for the principal amount of direct loans, and total loan principal, any part of which is to be guaranteed, not to exceed $100,000,000,000; and

(2) such amounts are available to cover all costs and expenditures as provided under section 149(e)(5)(B) of title 10, United States Code.

SEC. 20005. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR SCALING LOW-COST WEAPONS INTO PRODUCTION.

(a) APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $25,000,000 for the Office of Strategic Capital Global Technology Scout program;

(2) $1,400,000,000 for the expansion of the small unmanned aerial system industrial base;

(3) $400,000,000 for the development and deployment of the Joint Fires Network and associated joint battle management capabilities;

(4) $400,000,000 for the expansion of advanced command-and-control tools to combatant commands and military departments;

(5) $100,000,000 for the development of shared secure facilities for the defense industrial base;

(6) $50,000,000 for the creation of additional Defense Innovation Unit OnRamp Hubs;

(7) $600,000,000 for the acceleration of Strategic Capabilities Office programs;

(8) $650,000,000 for the expansion of Mission Capabilities office joint prototyping and experimentation activities for military innovation;

(9) $500,000,000 for the accelerated development and integration of advanced 5G/6G technologies for military use;

(10) $25,000,000 for testing of simultaneous transmit and receive technology for military spectrum agility;

(11) $50,000,000 for the development, procurement, and integration of high-altitude stratospheric balloons for military use;

(12) $120,000,000 for the development, procurement, and integration of long-endurance unmanned aerial systems for surveillance;

(13) $40,000,000 for the development, procurement, and integration of alternative positioning and navigation technology to enable military operations in contested electromagnetic environments;

(14) $750,000,000 for the acceleration of innovative military logistics and energy capability development and deployment;

(15) $125,000,000 for the acceleration of development of small, portable modular nuclear reactors for military use;

(16) $1,000,000,000 for the expansion of programs to accelerate the procurement and fielding of innovative technologies;

(17) $90,000,000 for the development of reusable hypersonic technology for military strikes;

(18) $2,000,000,000 for the expansion of Defense Innovation Unit scaling of commercial technology for military use;

(19) $500,000,000 to prevent delays in delivery of attritable autonomous military capabilities;

(20) $1,500,000,000 for the development, procurement, and integration of low-cost cruise missiles;

(21) $124,000,000 for improvements to Test Resource Management Center artificial intelligence capabilities;

(22) $145,000,000 for the development of artificial intelligence to enable one-way attack unmanned aerial systems and naval systems;

(23) $250,000,000 for the development of the Test Resource Management Center digital test environment;

(24) $250,000,000 for the advancement of the artificial intelligence ecosystem;

(25) $250,000,000 for the expansion of Cyber Command artificial intelligence lines of effort;

(26) $250,000,000 for the acceleration of the Quantum Benchmarking Initiative;

(27) $1,000,000,000 for the expansion and acceleration of qualification activities and technical data management to enhance competition in defense industrial base;

(28) $400,000,000 for the expansion of the defense manufacturing technology program;

(29) $1,685,000,000 for military cryptographic modernization activities;

(30) $90,000,000 for APEX Accelerators, the Mentor-Protege Program, and cybersecurity support to small non-traditional contractors;

(31) $250,000,000 for the development, procurement, and integration of Air Force low-cost counter-air capabilities;

(32) $10,000,000 for additional Air Force wargaming activities; and

(33) $20,000,000 for the Office of Strategic Capital workforce.

(b) APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $1,000,000,000 to the "Department of Defense Credit Program Account" to carry out the capital assistance program, including loans, loan guarantees, and technical assistance, established under section 149(e) of title 10, United States Code: *Provided*, That—

(1) such amounts are available to subsidize gross obligations for the principal amount of direct loans, and total loan principal, any part of which is to be guaranteed, not to exceed $100,000,000,000; and

(2) such amounts are available to cover all costs and expenditures as provided under section 149(e)(5)(B) of title 10, United States Code.

SEC. 20006. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR IMPROVING THE EFFICIENCY AND CYBERSECURITY OF THE DEPARTMENT OF DEFENSE.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $150,000,000 for business systems replacement to accelerate the audits of the financial statements of the Department of Defense pursuant to chapter 9A and section 2222 of title 10, United States Code;

(2) $200,000,000 for the deployment of automation and artificial intelligence to accelerate the audits of the financial

statements of the Department of Defense pursuant to chapter 9A and section 2222 of title 10, United States Code;

(3) $10,000,000 for the improvement of the budgetary and programmatic infrastructure of the Office of the Secretary of Defense; and

(4) $20,000,000 for defense cybersecurity programs of the Defense Advanced Research Projects Agency.

SEC. 20007. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR AIR SUPERIORITY.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $3,150,000,000 to increase F–15EX aircraft production;

(2) $361,220,000 to prevent the retirement of F–22 aircraft;

(3) $127,460,000 to prevent the retirement of F–15E aircraft;

(4) $187,000,000 to accelerate installation of F–16 electronic warfare capability;

(5) $116,000,000 for C–17A Mobility Aircraft Connectivity;

(6) $84,000,000 for KC–135 Mobility Aircraft Connectivity;

(7) $440,000,000 to increase C–130J production;

(8) $474,000,000 to increase EA–37B production;

(9) $678,000,000 to accelerate the Collaborative Combat Aircraft program;

(10) $400,000,000 to accelerate production of the F–47 aircraft;

(11) $750,000,000 accelerate the FA/XX aircraft;

(12) $100,000,000 for production of Advanced Aerial Sensors;

(13) $160,000,000 to accelerate V–22 nacelle and reliability and safety improvements;

(14) $100,000,000 to accelerate production of MQ–25 aircraft;

(15) $270,000,000 for development, procurement, and integration of Marine Corps unmanned combat aircraft;

(16) $96,000,000 for the procurement and integration of infrared search and track pods;

(17) $50,000,000 for the procurement and integration of additional F–15EX conformal fuel tanks;

(18) $600,000,000 for the development, procurement, and integration of Air Force long-range strike aircraft; and

(19) $500,000,000 for the development, procurement, and integration of Navy long-range strike aircraft.

SEC. 20008. ENHANCEMENT OF RESOURCES FOR NUCLEAR FORCES.

(a) DOD APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $2,500,000,000 for risk reduction activities for the Sentinel intercontinental ballistic missile program;

(2) $4,500,000,000 only for expansion of production capacity of B–21 long-range bomber aircraft and the purchase of aircraft only available through the expansion of production capacity;

(3) $500,000,000 for improvements to the Minuteman III intercontinental ballistic missile system;

(4) $100,000,000 for capability enhancements to intercontinental ballistic missile reentry vehicles;

(5) $148,000,000 for the expansion of D5 missile motor production;

(6) $400,000,000 to accelerate the development of Trident D5LE2 submarine-launched ballistic missiles;

(7) $2,000,000,000 to accelerate the development, procurement, and integration of the nuclear-armed sea-launched cruise missile;

(8) $62,000,000 to convert Ohio-class submarine tubes to accept additional missiles, not to be obligated before March 1, 2026;

(9) $168,000,000 to accelerate the production of the Survivable Airborne Operations Center program;

(10) $65,000,000 to accelerate the modernization of nuclear command, control, and communications;

(11) $210,300,000 for the increased production of MH–139 helicopters; and

(12) $150,000,000 to accelerate the development, procurement, and integration of military nuclear weapons delivery programs.

(b) NNSA APPROPRIATIONS.—In addition to amounts otherwise available, there are appropriated to the Administrator of the National Nuclear Security Administration for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $200,000,000 to perform National Nuclear Security Administration Phase 1 studies pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(2) $540,000,000 to address deferred maintenance and repair needs of the National Nuclear Security Administration pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(3) $1,000,000,000 to accelerate the construction of National Nuclear Security Administration facilities pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(4) $400,000,000 to accelerate the development, procurement, and integration of the warhead for the nuclear-armed sea-launched cruise missile pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(5) $750,000,000 to accelerate primary capability modernization pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(6) $750,000,000 to accelerate secondary capability modernization pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(7) $120,000,000 to accelerate domestic uranium enrichment centrifuge deployment for defense purposes pursuant to section 3211 of the National Nuclear Security Administration Act (50 U.S.C. 2401);

(8) $10,000,000 for National Nuclear Security Administration evaluation of spent fuel reprocessing technology; and

(9) $115,000,000 for accelerating nuclear national security missions through artificial intelligence.

SEC. 20009. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES TO IMPROVE CAPABILITIES OF UNITED STATES INDO-PACIFIC COMMAND.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $365,000,000 for Army exercises and operations in the Western Pacific area of operations;

(2) $53,000,000 for Special Operations Command exercises and operations in the Western Pacific area of operations;

(3) $47,000,000 for Marine Corps exercises and operations in Western Pacific area of operations;

(4) $90,000,000 for Air Force exercises and operations in Western Pacific area of operations;

(5) $532,600,000 for the Pacific Air Force biennial large-scale exercise;

(6) $19,000,000 for the development of naval small craft capabilities;

(7) $35,000,000 for military additive manufacturing capabilities in the United States Indo-Pacific Command area of operations west of the international dateline;

(8) $450,000,000 for the development of airfields within the area of operations of United States Indo-Pacific Command;

(9) $1,100,000,000 for development of infrastructure within the area of operations of United States Indo-Pacific Command;

(10) $124,000,000 for mission networks for United States Indo-Pacific Command;

(11) $100,000,000 for Air Force regionally based cluster pre-position base kits;

(12) $115,000,000 for exploration and development of existing Arctic infrastructure;

(13) $90,000,000 for the accelerated development of non-kinetic capabilities;

(14) $20,000,000 for United States Indo-Pacific Command military exercises;

(15) $143,000,000 for anti-submarine sonar arrays;

(16) $30,000,000 for surveillance and reconnaissance capabilities for United States Africa Command;

(17) $30,000,000 for surveillance and reconnaissance capabilities for United States Indo-Pacific Command;

(18) $500,000,000 for the development, coordination, and deployment of economic competition effects within the Department of Defense;

(19) $10,000,000 for the expansion of Department of Defense workforce for economic competition;

(20) $1,000,000,000 for offensive cyber operations;

(21) $500,000,000 for personnel and operations costs associated with forces assigned to United States Indo-Pacific Command;

(22) $300,000,000 for the procurement of mesh network communications capabilities for Special Operations Command Pacific;

(23) $850,000,000 for the replenishment of military articles;

(24) $200,000,000 for acceleration of Guam Defense System program;

(25) $68,000,000 for Space Force facilities improvements;

(26) $150,000,000 for ground moving target indicator military satellites;

(27) $528,000,000 for DARC and SILENTBARKER military space situational awareness programs;

(28) $80,000,000 for Navy Operational Support Division;

(29) $1,000,000,000 for the X–37B military spacecraft program;

(30) $3,650,000,000 for the development, procurement, and integration of United States military satellites and the protection of United States military satellites.

(31) $125,000,000 for the development, procurement, and integration of military space communications.

(32) $350,000,000 for the development, procurement, and integration of military space command and control systems.

SEC. 20010. ENHANCEMENT OF DEPARTMENT OF DEFENSE RESOURCES FOR IMPROVING THE READINESS OF THE DEPARTMENT OF DEFENSE.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $1,400,000,000 for a pilot program on OPN-8 maritime spares and repair rotable pool;

(2) $700,000,000 for a pilot program on OPN-8 maritime spares and repair rotable pool for amphibious ships;

(3) $2,118,000,000 for spares and repairs to keep Air Force aircraft mission capable;

(4) $1,500,000,000 for Army depot modernization and capacity enhancement;

(5) $2,000,000,000 for Navy depot and shipyard modernization and capacity enhancement;

(6) $250,000,000 for Air Force depot modernization and capacity enhancement;

(7) $1,640,000,000 for Special Operations Command equipment, readiness, and operations;

(8) $500,000,000 for National Guard unit readiness;

(9) $400,000,000 for Marine Corps readiness and capabilities;

(10) $20,000,000 for upgrades to Marine Corps utility helicopters;

(11) $310,000,000 for next-generation vertical lift, assault, and intra-theater aeromedical evacuation aircraft;

(12) $75,000,000 for the procurement of anti-lock braking systems for Army wheeled transport vehicles;

(13) $230,000,000 for the procurement of Army wheeled combat vehicles;

(14) $63,000,000 for the development of advanced rotary-wing engines;

(15) $241,000,000 for the development, procurement, and integration of Marine Corps amphibious vehicles;

(16) $250,000,000 for the procurement of Army tracked combat transport vehicles;

(17) $98,000,000 for additional Army light rotary-wing capabilities;

(18) $1,500,000,000 for increased depot maintenance and shipyard maintenance activities;

(19) $2,500,000,000 for Air Force facilities sustainment, restoration, and modernization;

(20) $92,500,000 for the completion of Robotic Combat Vehicle prototyping;

(21) $125,000,000 for Army operations;

(22) $10,000,000 for the Air Force Concepts, Development, and Management Office; and

(23) $320,000,000 for Joint Special Operations Command.

SEC. 20011. IMPROVING DEPARTMENT OF DEFENSE BORDER SUPPORT AND COUNTER-DRUG MISSIONS.

In addition to amounts otherwise available, there are appropriated to the Secretary of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $1,000,000,000 for the deployment of military personnel in support of border operations, operations and maintenance activities in support of border operations, counter-narcotics and counter-transnational criminal organization mission support, the operation of national defense areas and construction in national defense areas, and the temporary detention of migrants on Department of Defense installations, in accordance with chapter 15 of title 10, United States Code.

SEC. 20012. DEPARTMENT OF DEFENSE OVERSIGHT.

In addition to amounts otherwise available, there is appropriated to the Inspector General of the Department of Defense for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $10,000,000, to remain available through September 30, 2029, to monitor Department of Defense activities for which funding is appropriated in this title, including—

(1) programs with mutual technological dependencies;

(2) programs with related data management and data ownership considerations; and

(3) programs particularly vulnerable to supply chain disruptions and long lead time components.

SEC. 20013. MILITARY CONSTRUCTION PROJECTS AUTHORIZED.

(a) AUTHORIZATION OF APPROPRIATIONS.—Funds are hereby authorized to be appropriated for military construction, land acquisition, and military family housing functions of each military department (as defined in section 101(a) of title 10, United States Code) as specified in this title.

(b) SPENDING PLAN.—Not later than 30 days after the date of the enactment of this title, the Secretary of each military department shall submit to the Committees on Armed Services of the Senate and House of Representatives a detailed spending plan by project for all funds made available by this title to be expended on military construction projects.

TITLE III—COMMITTEE ON BANKING, HOUSING, AND URBAN AFFAIRS

SEC. 30001. FUNDING CAP FOR THE BUREAU OF CONSUMER FINANCIAL PROTECTION.

Section 1017(a)(2)(A)(iii) of the Consumer Financial Protection Act of 2010 (12 U.S.C. 5497(a)(2)(A)(iii)) is amended by striking "12" and inserting "6.5".

SEC. 30002. RESCISSION OF FUNDS FOR GREEN AND RESILIENT RETROFIT PROGRAM FOR MULTIFAMILY HOUSING.

The unobligated balances of amounts made available under section 30002(a) of the Act entitled "An Act to provide for reconciliation pursuant to title II of S. Con. Res. 14", approved August 16, 2022 (Public Law 117–169; 136 Stat. 2027) are rescinded.

SEC. 30003. SECURITIES AND EXCHANGE COMMISSION RESERVE FUND.

(a) IN GENERAL.—Section 4 of the Securities Exchange Act of 1934 (15 U.S.C. 78d) is amended—

(1) by striking subsection (i); and

(2) by redesignating subsections (j) and (k) as subsections (i) and (j), respectively.

(b) TECHNICAL AND CONFORMING AMENDMENT.—Section 21F(g)(2) of the Securities Exchange Act of 1934 (15 U.S.C. 78u–6(g)(2)) is amended to read as follows:

"(a) USE OF FUND.—The Fund shall be available to the Commission, without further appropriation or fiscal year limitation, for paying awards to whistleblowers as provided in subsection (b).".

(c) TRANSITION PROVISION.—During the period beginning on the date of enactment of this Act and ending on October 1, 2025, the Securities and Exchange Commission may expend amounts in the Securities and Exchange Commission Reserve Fund that were obligated before the date of enactment of this Act for any program, project, or activity that is ongoing (as of the day before the date of enactment of this Act) in accordance with subsection (i) of section 4 of the Securities Exchange Act of 1934 (15 U.S.C. 78d), as in effect on the day before the date of enactment of this Act.

(d) TRANSFER OF REMAINING AMOUNTS.—Effective on October 1, 2025, the obligated and unobligated balances of amounts in the Securities and Exchange Commission Reserve Fund shall be transferred to the general fund of the Treasury.

(e) CLOSING OF ACCOUNT.—For the purposes of section 1555 of title 31, United States Code, the Securities and Exchange Commission Reserve Fund shall be considered closed, and thereafter shall not be available for obligation or expenditure for any purpose, upon execution of the transfer required under subsection (d).

SEC. 30004. APPROPRIATIONS FOR DEFENSE PRODUCTION ACT.

In addition to amounts otherwise available, there is appropriated for fiscal year 2025, out of amounts not otherwise appropriated, $1,000,000,000, to remain available until September 30, 2027, to carry out the Defense Production Act (50 U.S.C. 4501 et seq.).

TITLE IV—COMMITTEE ON COMMERCE, SCIENCE, AND TRANSPORTATION

SEC. 40001. COAST GUARD MISSION READINESS.

(a) IN GENERAL.—Chapter 11 of title 14, United States Code, is amended by adding at the end the following:

"Subchapter V—Coast Guard Mission Readiness

"§ 1181. Special appropriations

"In addition to amounts otherwise available, there is appropriated to the Coast Guard for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $24,593,500,000, to remain available until September 30, 2029, notwithstanding paragraphs (1) and (2) of section 1105(a) and sections 1131, 1132, 1133, and 1156, to use expedited processes to procure or acquire new operational assets and systems, to maintain existing assets and systems, to design, construct, plan, engineer, and improve necessary shore infrastructure, and to enhance operational resilience for monitoring, search and rescue, interdiction, hardening of maritime approaches, and navigational safety, of which—

"(1) $1,142,500,000 is provided for procurement and acquisition of fixed-wing aircraft, equipment related to such aircraft and training simulators and program management for such aircraft, to provide for security of the maritime border;

"(2) $2,283,000,000 is provided for procurement and acquisition of rotary-wing aircraft, equipment related to such aircraft and training simulators and program management for such aircraft, to provide for security of the maritime border;

"(3) $266,000,000 is provided for procurement and acquisition of long-range unmanned aircraft and base stations, equipment related to such aircraft and base stations, and program management for such aircraft and base stations, to provide for security of the maritime border;

"(4) $4,300,000,000 is provided for procurement of Offshore Patrol Cutters, equipment related to such cutters, and program management for such cutters, to provide operational presence and security of the maritime border and for interdiction of persons and controlled substances;

"(5) $1,000,000,000 is provided for procurement of Fast Response Cutters, equipment related to such cutters, and program management for such cutters, to provide operational presence and security of the maritime border and for interdiction of persons and controlled substances;

"(6) $4,300,000,000 is provided for procurement of Polar Security Cutters, equipment related to such cutters, and program management for such cutters, to ensure timely presence of the Coast Guard in the Arctic and Antarctic regions;

"(7) $3,500,000,000 is provided for procurement of Arctic Security Cutters, equipment related to such cutters, and program management for such cutters, to ensure timely presence of the Coast Guard in the Arctic and Antarctic regions;

"(8) $816,000,000 is provided for procurement of light and medium icebreaking cutters, and equipment relating to such cutters, from shipyards that have demonstrated success in the cost-effective application of design standards and in delivering, on schedule and within budget, vessels of a size and tonnage that are not less than the size and tonnage of the cutters described in this paragraph, and for program management for such cutters, to expand domestic icebreaking capacity;

"(9) $162,000,000 is provided for procurement of Waterways Commerce Cutters, equipment related to such cutters, and program management for such cutters, to support aids to navigation, waterways and coastal security, and search and rescue in inland waterways;

"(10) $4,379,000,000 is provided for design, planning, engineering, recapitalization, construction, rebuilding, and improvement of, and program management for, shore facilities, of which—

"(A) $425,000,000 is provided for design, planning, engineering, construction of, and program management for—

"(i) the enlisted boot camp barracks and multi-use training center; and

"(ii) other related facilities at the enlisted boot camp;

"(B) $500,000,000 is provided for—

"(i) construction, improvement, and dredging at the Coast Guard Yard; and

"(ii) acquisition of a floating drydock for the Coast Guard Yard;

"(C) not more than $2,729,500,000 is provided for homeports and hangars for cutters and aircraft for which funds are appropriated under paragraph (1) through (9); and

"(D) $300,000,000 is provided for homeporting of the existing polar icebreaker commissioned into service in 2025;

"(11) $2,200,000,000 is provided for aviation, cutter, and shore facility depot maintenance and maintenance of command, control, communication, computer, and cyber assets;

"(12) $170,000,000 is provided for improving maritime domain awareness on the maritime border, at United States ports, at land-based facilities and in the cyber domain; and

"(13) $75,000,000 is provided to contract the services of, acquire, or procure autonomous maritime systems.".

(b) TECHNICAL AND CONFORMING AMENDMENT.—The analysis for chapter 11 of title 14, United States Code, is amended by adding at the end the following:

"SUBCHAPTER V—COAST GUARD MISSION READINESS

"1181. Special appropriations.".

SEC. 40002. SPECTRUM AUCTIONS.

(a) DEFINITIONS.—In this section:

(1) ASSISTANT SECRETARY.—The term "Assistant Secretary" means the Assistant Secretary of Commerce for Communications and Information.

(2) COMMISSION.—The term "Commission" means the Federal Communications Commission.

(3) COVERED BAND.—The term "covered band"—

(A) except as provided in subparagraph (B), means the band of frequencies between 1.3 gigahertz and 10.5 gigahertz; and

(B) does not include—

(i) the band of frequencies between 3.1 gigahertz and 3.45 gigahertz for purposes of auction, reallocation, modification, or withdrawal; or

(ii) the band of frequencies between 7.4 gigahertz and 8.4 gigahertz for purposes of auction, reallocation, modification, or withdrawal.

(4) FULL-POWER COMMERCIAL LICENSED USE CASES.—The term "full-power commercial licensed use cases" means flexible use wireless broadband services with base station power levels sufficient for high-power, high-density, and wide-area commercial mobile services, consistent with the service rules under part 27 of title 47, Code of Federal Regulations, or any successor regulations, for wireless broadband deployments throughout the covered band.

(b) GENERAL AUCTION AUTHORITY.—

(1) AMENDMENT.—Section 309(j)(11) of the Communications Act of 1934 (47 U.S.C. 309(j)(11)) is amended by striking "grant a license or permit under this subsection shall expire March 9, 2023" and all that follows and inserting the following: "complete a system of competitive bidding under this subsection shall expire September 30, 2034, except that, with respect to the electromagnetic spectrum— "

"(A) between the frequencies of 3.1 gigahertz and 3.45 gigahertz, such authority shall not apply; and

"(B) between the frequencies of 7.4 gigahertz and 8.4 gigahertz, such authority shall not apply.".

(2) SPECTRUM AUCTIONS.—The Commission shall grant licenses through systems of competitive bidding, before the expiration of the general auction authority of the Commission under section 309(j)(11) of the Communications Act of 1934 (47 U.S.C. 309(j)(11)), as amended by paragraph (1) of this subsection, for not less than 300 megahertz, including by completing a system of competitive bidding not later than 2 years after the date of enactment of this Act for not less than 100 megahertz in the band between 3.98 gigahertz and 4.2 gigahertz.

(c) IDENTIFICATION FOR REALLOCATION.—

(1) IN GENERAL.—The Assistant Secretary, in consultation with the Commission, shall identify 500 megahertz of frequencies in the covered band for reallocation to non-Federal use, shared Federal and non-Federal use, or a combination thereof, for full-power commercial licensed use cases, that—

(A) as of the date of enactment of this Act, are allocated for Federal use; and

(B) shall be in addition to the 300 megahertz of frequencies for which the Commission grants licenses under subsection (b)(2).

(2) SCHEDULE.—The Assistant Secretary shall identify the frequencies under paragraph (1) according to the following schedule:

(A) Not later than 2 years after the date of enactment of this Act, the Assistant Secretary shall identify not less than 200 megahertz of frequencies within the covered band.

(B) Not later than 4 years after the date of enactment of this Act, the Assistant Secretary shall identify any remaining bandwidth required to be identified under paragraph (1).

(3) REQUIRED ANALYSIS.—

(A) IN GENERAL.—In determining under paragraph (1) which specific frequencies within the covered band to reallocate, the Assistant Secretary shall determine the feasibility of the reallocation of frequencies.

(B) REQUIREMENTS.—In conducting the analysis under subparagraph (A), the Assistant Secretary shall assess net revenue potential, relocation or sharing costs, as applicable, and the feasibility of reallocating specific frequencies, with the goal of identifying the best approach to maximize net proceeds of systems of competitive bidding for the Treasury, consistent with section 309(j) of the Communications Act of 1934 (47 U.S.C. 309(j)).

(d) AUCTIONS.—The Commission shall grant licenses for the frequencies identified for reallocation under subsection (c) through systems of competitive bidding in accordance with the following schedule:

(1) Not later than 4 years after the date of enactment of this Act, the Commission shall, after notifying the Assistant Secretary, complete 1 or more systems of competitive bidding for not less than 200 megahertz of the frequencies.

(2) Not later than 8 years after the date of enactment of this Act, the Commission shall, after notifying the Assistant Secretary, complete 1 or more systems of competitive bidding for any frequencies identified under subsection (c) that remain to be auctioned after compliance with paragraph (1) of this subsection.

(e) LIMITATION.—The President shall modify or withdraw any frequency proposed for reallocation under this section not later than 60 days before the commencement of a system of competitive bidding scheduled by the Commission with respect to that frequency, if the President determines that such modification or withdrawal is necessary to protect the national security of the United States.

(f) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Department of Commerce for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $50,000,000, to remain available through September 30, 2034, to provide additional support to the Assistant Secretary to—

(1) conduct a timely spectrum analysis of the bands of frequencies—

(A) between 2.7 gigahertz and 2.9 gigahertz;

(B) between 4.4 gigahertz and 4.9 gigahertz; and

(C) between 7.25 gigahertz and 7.4 gigahertz; and

(2) publish a biennial report, with the last report to be published not later than June 30, 2034, on the value of all spectrum used by Federal entities (as defined in section 113(l) of the National Telecommunications and Information Administration Organization Act (47 U.S.C. 923(l))), that assesses the value of bands of frequencies in increments of not more than 100 megahertz.

SEC. 40003. AIR TRAFFIC CONTROL IMPROVEMENTS.

(a) IN GENERAL.—For the purpose of the acquisition, construction, sustainment, and improvement of facilities and equipment necessary to improve or maintain aviation safety, in addition to amounts otherwise made available, there is appropriated to the Administrator of the Federal Aviation Administration for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $4,750,000,000 for telecommunications infrastructure modernization and systems upgrades;

(2) $3,000,000,000 for radar systems replacement;

(3) $500,000,000 for runway safety technologies, runway lighting systems, airport surface surveillance technologies, and to carry out section 347 of the FAA Reauthorization Act of 2024;

(4) $300,000,000 for Enterprise Information Display Systems;

(5) $80,000,000 to acquire and install not less than 50 Automated Weather Observing Systems, to acquire and install not less than 60 Visual Weather Observing Systems, to acquire and install not less than 64 weather camera sites, and to acquire and install weather stations;

(6) $40,000,000 to carry out section 44745 of title 49, United States Code, (except for activities described in paragraph (5));

(7) $1,900,000,000 for necessary actions to construct a new air route traffic control center (in this subsection referred to as "ARTCC"): *Provided*, That not more than 2 percent of such amount is used for planning or administrative purposes: *Provided further*, That at least 3 existing ARTCCs are divested and integrated into the newly constructed ARTCC;

(8) $100,000,000 to conduct an ARTCC Realignment and Consolidation Effort under which at least 10 existing ARTCCs are closed or consolidated to facilitate recapitalization of ARTCC facilities owned and operated by the Federal Aviation Administration;

(9) $1,000,000,000 to support recapitalization and consolidation of terminal radar approach control facilities (in this subsection referred to as "TRACONs"), the analysis and identification of TRACONs for divestment, consolidation, or integration, planning, site selection, facility acquisition, and transition activities and other appropriate activities for carrying out such divestment, consolidation, or integration, and the establishment of brand new TRACONs;

(10) $350,000,000 for unstaffed infrastructure sustainment and replacement;

(11) $50,000,000 to carry out section 961 of the FAA Reauthorization Act of 2024;

(12) $300,000,000 to carry out section 619 of the FAA Reauthorization Act of 2024;

(13) $50,000,000 to carry out section 621 of the FAA Reauthorization Act of 2024 and to deploy remote tower technology at untowered airports; and

(14) $100,000,000 for air traffic controller advanced training technologies.

(b) QUARTERLY REPORTING.—Not later than 180 days after the date of enactment of this Act, and every 90 days thereafter, the Administrator of the Federal Aviation Administration shall submit to Congress a report that describes any expenditures under this section.

SEC. 40004. SPACE LAUNCH AND REENTRY LICENSING AND PERMITTING USER FEES.

(a) IN GENERAL.—Chapter 509 of title 51, United States Code, is amended by adding at the end the following new section:

"§ 50924. Space launch and reentry licensing and permitting user fees

"(a) FEES.—

"(1) IN GENERAL.—The Secretary of Transportation shall impose a fee, which shall be deposited in the account established under subsection (b), on each launch or reentry carried out under a license or permit issued under section 50904 during 2026 or a subsequent year, in an amount equal to the lesser of—

"(A) the amount specified in paragraph (2) for the year involved per pound of the weight of the payload; or

"(B) the amount specified in paragraph (3) for the year involved.

"(2) PARAGRAPH (2) SPECIFIED AMOUNT.—The amount specified in this paragraph is—

"(A) for 2026, $0.25;
"(B) for 2027, $0.35;
"(C) for 2028, $0.50;
"(D) for 2029, $0.60;
"(E) for 2030, $0.75;
"(F) for 2031, $1;
"(G) for 2032, $1.25;
"(H) for 2033, $1.50; and
"(I) for 2034 and each subsequent year, the amount specified in this paragraph for the previous year increased by the percentage increase in the consumer price index for all urban consumers (all items; United States city average) over the previous year.

"(3) PARAGRAPH (3) SPECIFIED AMOUNT.—The amount specified in this paragraph is—

"(A) for 2026, $30,000;
"(B) for 2027, $40,000;
"(C) for 2028, $50,000;
"(D) for 2029, $75,000;
"(E) for 2030, $100,000;
"(F) for 2031, $125,000;
"(G) for 2032, $170,000;
"(H) for 2033, $200,000; and
"(I) for 2034 and each subsequent year, the amount specified in this paragraph for the previous year increased by the percentage increase in the consumer price index for all urban consumers (all items; United States city average) over the previous year.

"(b) OFFICE OF COMMERCIAL SPACE TRANSPORTATION LAUNCH AND REENTRY LICENSING AND PERMITTING FUND.—There is established in the Treasury of the United States a separate account, which shall be known as the 'Office of Commercial Space Transportation Launch and Reentry Licensing and Permitting Fund', for the purposes of expenses of the Office of Commercial Space Transportation of the Federal Aviation Administration and to carry out section 630(b) of the FAA Reauthorization Act of 2024. 70 percent of the amounts deposited into the fund shall be available for such purposes and shall be available without further appropriation and without fiscal year limitation.''.

(b) CLERICAL AMENDMENT.—The table of sections for chapter 509 of title 51, United States Code, is amended by inserting after the item relating to section 50923 the following:

"50924. Space launch and reentry licensing and permitting user fees.''.

SEC. 40005. MARS MISSIONS, ARTEMIS MISSIONS, AND MOON TO MARS PROGRAM.

(a) IN GENERAL.—Chapter 203 of title 51, United States Code, is amended by adding at the end the following:

"§ 20306. Special appropriations for Mars missions, Artemis missions, and Moon to Mars program

"(a) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Administration for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $9,995,000,000, to remain available until September 30, 2032, to use as follows:

"(1) $700,000,000, to be obligated not later than fiscal year 2026, for the procurement, using a competitively bid, firm fixed-price contract with a United States commercial provider (as defined in section 50101(7)), of a high-performance Mars telecommunications orbiter—

"(A) that—

"(i) is capable of providing robust, continuous communications for—

"(I) a Mars sample return mission, as described in section 432(3)(C) of the National Aeronautics and Space Administration Transition Authorization Act of 2017 (51 U.S.C. 20302 note; Public Law 115–10); and

"(II) future Mars surface, orbital, and human exploration missions;

"(ii) supports autonomous operations, onboard processing, and extended mission duration capabilities; and

"(iii) is selected from among the commercial proposals that—

"(I) received funding from the Administration in fiscal year 2024 or 2025 for commercial design studies for Mars Sample Return; and

"(II) proposed a separate, independently launched Mars telecommunication orbiter supporting an end-to-end Mars sample return mission; and

"(B) which shall be delivered to the Administration not later than December 31, 2028.

"(2) $2,600,000,000 to meet the requirements of section 20302(a) using the program of record known, as of the date of the enactment of this section, as 'Gateway', and as described in section 10811(b)(2)(B)(iv) of the National Aeronautics and Space Administration Authorization Act of 2022 (51 U.S.C.

20302 note; Public Law 117–167), of which not less than $750,000,000 shall be obligated for each of fiscal years 2026, 2027, and 2028.

"(3) $4,100,000,000 for expenses related to meeting the requirements of section 10812 of the National Aeronautics and Space Administration Authorization Act of 2022 (51 U.S.C. 20301; Public Law 117–167) for the procurement, transportation, integration, operation, and other necessary expenses of the Space Launch System for Artemis Missions IV and V, of which not less than $1,025,000,000 shall be obligated for each of fiscal years 2026, 2027, 2028, and 2029.

"(4) $20,000,000 for expenses related to the continued procurement of the multi-purpose crew vehicle described in section 303 of the National Aeronautics and Space Administration Authorization Act of 2010 (42 U.S.C. 18323), known as the 'Orion', for use with the Space Launch System on the Artemis IV Mission and reuse in subsequent Artemis Missions, of which not less than $20,000,000 shall be obligated not later than fiscal year 2026.

"(5) $1,250,000,000 for expenses related to the operation of the International Space Station and for the purpose of meeting the requirement under section 503(a) of the National Aeronautics and Space Administration Authorization Act of 2010 (42 U.S.C. 18353(a)), of which not less than $250,000,000 shall be obligated for such expenses for each of fiscal years 2025, 2026, 2027, 2028, and 2029.

"(6) $1,000,000,000 for infrastructure improvements at the manned spaceflight centers of the Administration, of which not less than—

"(A) $120,000,000 shall be obligated not later than fiscal year 2026 for construction, revitalization, recapitalization, or other infrastructure projects and improvements at the center described in Executive Order 12641 (53 Fed. Reg. 18816; relating to designating certain facilities of the National Aeronautics and Space Administration in the State of Mississippi as the John C. Stennis Space Center);

"(B) $250,000,000 shall be obligated not later than fiscal year 2026 for construction, revitalization, recapitalization, or other infrastructure projects and improvements at the center described in Executive Order 11129 (28 Fed. Reg. 12787; relating to designating certain facilities of the National Aeronautics and Space Administration and of the Department of Defense, in the State of Florida, as the John F. Kennedy Space Center);

"(C) $300,000,000 shall be obligated not later than fiscal year 2026 for construction, revitalization, recapitalization, or other infrastructure projects and improvements at the center described in the Joint Resolution entitled 'Joint Resolution to designate the Manned Spacecraft Center in Houston, Texas, as the "Lyndon B. Johnson Space Center" in honor of the late President', approved February 17, 1973 (Public Law 93–8; 87 Stat. 7);

"(D) $100,000,000 shall be obligated not later than fiscal year 2026 for construction, revitalization, recapitalization, or other infrastructure projects and improvements at the center described in Executive Order 10870 (25 Fed. Reg. 2197; relating to designating the facilities of the

National Aeronautics and Space Administration at Huntsville, Alabama, as the George C. Marshall Space Flight Center);

"(E) $30,000,000 shall be obligated not later than fiscal year 2026 for construction, revitalization, recapitalization, or other infrastructure projects and improvements at the Michoud Assembly Facility in New Orleans, Louisiana; and

"(F) $85,000,000 shall be obligated to carry out subsection (b), of which not less than $5,000,000 shall be obligated for the transportation of the space vehicle described in that subsection, with the remainder transferred not later than the date that is 18 months after the date of the enactment of this section to the entity designated under that subsection, for the purpose of construction of a facility to house the space vehicle referred to in that subsection.

"(7) $325,000,000 to fulfill contract number 80JSC024CA002 issued by the National Aeronautics and Space Administration on June 26, 2024.

"(b) SPACE VEHICLE TRANSFER.—

"(1) IN GENERAL.—Not later than 30 days after the date of the enactment of this section, the Administrator shall identify a space vehicle described in paragraph (2) to be—

"(A) transferred to a field center of the Administration that is involved in the administration of the Commercial Crew Program (as described in section 302 of the National Aeronautics and Space Administration Transition Authorization Act of 2017 (51 U.S.C. 50111 note; Public Law 115–10)); and

"(B) placed on public exhibition at an entity within the Metropolitan Statistical Area where such center is located.

"(2) SPACE VEHICLE DESCRIBED.—A space vehicle described in this paragraph is a vessel that—

"(A) has flown into space;

"(B) has carried astronauts; and

"(C) is selected with the concurrence of an entity designated by the Administrator.

"(3) TRANSFER.—Not later than 18 months after the date of the enactment of this section, the space vehicle identified under paragraph (1) shall be transferred to an entity designated by the Administrator.

"(c) OBLIGATION OF FUNDS.—Funds appropriated under subsection (a) shall be obligated as follows:

"(1) Not less than 50 percent of the total funds in subsection (a) shall be obligated not later than September 30, 2028.

"(2) 100 percent of funds shall be obligated not later than September 30, 2029.

"(3) All associated outlays shall occur not later than September 30, 2034.".

(b) CLERICAL AMENDMENT.—The table of sections for chapter 203 of title 51, United States Code, is amended by adding at the end the following:

"20306. Special appropriations for Mars missions, Artemis missions, and Moon to Mars program.".

SEC. 40006. CORPORATE AVERAGE FUEL ECONOMY CIVIL PENALTIES.

(a) IN GENERAL.—Section 32912 of title 49, United States Code, is amended—

(1) in subsection (b), in the matter preceding paragraph (1), by striking "$5" and inserting "$0.00"; and

(2) in subsection (c)(1)(B), by striking "$10" and inserting "$0.00".

(b) EFFECT; APPLICABILITY.—The amendments made by subsection (a) shall—

(1) take effect on the date of enactment of this section; and

(2) apply to all model years of a manufacturer for which the Secretary of Transportation has not provided a notification pursuant to section 32903(b)(2)(B) of title 49, United States Code, specifying the penalty due for the average fuel economy of that manufacturer being less than the applicable standard prescribed under section 32902 of that title.

SEC. 40007. PAYMENTS FOR LEASE OF METROPOLITAN WASHINGTON AIRPORTS.

Section 49104(b) of title 49, United States Code, is amended to read as follows:

"(b) PAYMENTS.—

"(1) IN GENERAL.—Subject to paragraph (2), under the lease, the Airports Authority must pay to the general fund of the Treasury annually an amount, computed using the GNP Price Deflator—

"(A) during the period from 1987 to 2026, equal to $3,000,000 in 1987 dollars; and

"(B) for 2027 and subsequent years, equal to $15,000,000 in 2027 dollars.

"(2) RENEGOTIATION.—The Secretary and the Airports Authority shall renegotiate the level of lease payments at least once every 10 years to ensure that in no year the amount specified in paragraph (1)(B) is less than $15,000,000 in 2027 dollars.".

SEC. 40008. RESCISSION OF CERTAIN AMOUNTS FOR THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION.

Any unobligated balances of amounts appropriated or otherwise made available by sections 40001, 40002, 40003, and 40004 of Public Law 117–169 (136 Stat. 2028) are hereby rescinded.

SEC. 40009. REDUCTION IN ANNUAL TRANSFERS TO TRAVEL PROMOTION FUND.

Subsection (d)(2)(B) of the Travel Promotion Act of 2009 (22 U.S.C. 2131(d)(2)(B)) is amended by striking "$100,000,000" and inserting "$20,000,000".

SEC. 40010. TREATMENT OF UNOBLIGATED FUNDS FOR ALTERNATIVE FUEL AND LOW-EMISSION AVIATION TECHNOLOGY.

Out of the amounts made available by section 40007(a) of title IV of Public Law 117–169 (49 U.S.C. 44504 note), any unobligated balances of such amounts are hereby rescinded.

SEC. 40011. RESCISSION OF AMOUNTS APPROPRIATED TO PUBLIC WIRELESS SUPPLY CHAIN INNOVATION FUND.

Of the unobligated balances of amounts made available under section 106(a) of the CHIPS Act of 2022 (Public Law 117–167; 136 Stat. 1392), $850,000,000 are permanently rescinded.

TITLE V—COMMITTEE ON ENERGY AND NATURAL RESOURCES

Subtitle A—Oil and Gas Leasing

SEC. 50101. ONSHORE OIL AND GAS LEASING.

(a) REPEAL OF INFLATION REDUCTION ACT PROVISIONS.—

(1) ONSHORE OIL AND GAS ROYALTY RATES.—Subsection (a) of section 50262 of Public Law 117–169 (136 Stat. 2056) is repealed, and any provision of law amended or repealed by that subsection is restored or revived as if that subsection had not been enacted into law.

(2) NONCOMPETITIVE LEASING.—Subsection (e) of section 50262 of Public Law 117–169 (136 Stat. 2057) is repealed, and any provision of law amended or repealed by that subsection is restored or revived as if that subsection had not been enacted into law.

(b) REQUIREMENT TO IMMEDIATELY RESUME ONSHORE OIL AND GAS LEASE SALES.—

(1) IN GENERAL.—The Secretary of the Interior shall immediately resume quarterly onshore oil and gas lease sales in compliance with the Mineral Leasing Act (30 U.S.C. 181 et seq.).

(2) REQUIREMENT.—The Secretary of the Interior shall ensure—

(A) that any oil and gas lease sale required under paragraph (1) is conducted immediately on completion of all applicable scoping, public comment, and environmental analysis requirements under the Mineral Leasing Act (30 U.S.C. 181 et seq.) and the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.); and

(B) that the processes described in subparagraph (A) are conducted in a timely manner to ensure compliance with subsection (b)(1).

(3) LEASE OF OIL AND GAS LANDS.—Section 17(b)(1)(A) of the Mineral Leasing Act (30 U.S.C. 226(b)(1)(A)), as amended by subsection (a), is amended by inserting "For purposes of the previous sentence, the term 'eligible lands' means all lands that are subject to leasing under this Act and are not excluded from leasing by a statutory prohibition, and the term 'available', with respect to eligible lands, means those lands that have been designated as open for leasing under a land use plan developed under section 202 of the Federal Land Policy and

Management Act of 1976 (43 U.S.C. 1712) and that have been nominated for leasing through the submission of an expression of interest, are subject to drainage in the absence of leasing, or are otherwise designated as available pursuant to regulations adopted by the Secretary." after "sales are necessary.".

(c) QUARTERLY LEASE SALES.—

(1) IN GENERAL.—In accordance with the Mineral Leasing Act (30 U.S.C. 181 et seq.), each fiscal year, the Secretary of the Interior shall conduct a minimum of 4 oil and gas lease sales of available land in each of the following States:

(A) Wyoming.

(B) New Mexico.

(C) Colorado.

(D) Utah.

(E) Montana.

(F) North Dakota.

(G) Oklahoma.

(H) Nevada.

(I) Alaska.

(2) REQUIREMENT.—In conducting a lease sale under paragraph (1) in a State described in that paragraph, the Secretary of the Interior—

(A) shall offer not less than 50 percent of available parcels nominated for oil and gas development under the applicable resource management plan in effect for relevant Bureau of Land Management resource management areas within the applicable State; and

(B) shall not restrict the parcels offered to 1 Bureau of Land Management field office within the applicable State unless all nominated parcels are located within the same Bureau of Land Management field office.

(3) REPLACEMENT SALES.—The Secretary of the Interior shall conduct a replacement sale during the same fiscal year if—

(A) a lease sale under paragraph (1) is canceled, delayed, or deferred, including for a lack of eligible parcels; or

(B) during a lease sale under paragraph (1) the percentage of acreage that does not receive a bid is equal to or greater than 25 percent of the acreage offered.

(d) MINERAL LEASING ACT REFORMS.—Section 17 of the Mineral Leasing Act (30 U.S.C. 226), as amended by subsection (a), is amended—

(1) by striking the section designation and all that follows through the end of subsection (a) and inserting the following:

"SEC. 17. LEASING OF OIL AND GAS PARCELS.

"(a) LEASING AUTHORIZED.—

"(1) IN GENERAL.—Any parcel of land subject to disposition under this Act that is known or believed to contain oil or gas deposits shall be made available for leasing, subject to paragraph (2), by the Secretary of the Interior, not later than 18 months after the date of receipt by the Secretary of an expression of interest in leasing the applicable parcel of land available for disposition under this section, if the Secretary determines that the parcel of land is open to oil or gas leasing under the approved resource management plan applicable to the planning area in which the parcel of land is located that is in effect on the date on which the expression of interest was submitted to the Secretary (referred to in this subsection as the 'approved resource management plan').

"(2) RESOURCE MANAGEMENT PLANS.—

"(A) LEASE TERMS AND CONDITIONS.—A lease issued by the Secretary under this section with respect to an applicable parcel of land made available for leasing under paragraph (1)—

"(i) shall be subject to the terms and conditions of the approved resource management plan; and

"(ii) may not require any stipulations or mitigation requirements not included in the approved resource management plan.

"(B) EFFECT OF AMENDMENT.—The initiation of an amendment to an approved resource management plan shall not prevent or delay the Secretary from making the applicable parcel of land available for leasing in accordance with that approved resource management plan if the other requirements of this section have been met, as determined by the Secretary.";

(2) in subsection (p), by adding at the end the following:

"(4) TERM.—A permit to drill approved under this subsection shall be valid for a single, non-renewable 4-year period beginning on the date that the permit to drill is approved."; and

(3) by striking subsection (q) and inserting the following:

"(q) COMMINGLING OF PRODUCTION.—The Secretary of the Interior shall approve applications allowing for the commingling of production from 2 or more sources (including the area of an oil and gas lease, the area included in a drilling spacing unit, a unit participating area, a communitized area, or non-Federal property) before production reaches the point of royalty measurement regardless of ownership, the royalty rates, and the number or percentage of acres for each source if the applicant agrees to install measurement devices for each source, utilize an allocation method that achieves volume measurement uncertainty levels within plus or minus 2 percent during the production phase reported on a monthly basis, or utilize an approved periodic well testing methodology. Production from multiple oil and gas leases, drilling spacing units, communitized areas, or participating areas from a single wellbore shall be considered a single source. Nothing in this subsection shall prevent the Secretary of the Interior from continuing the current practice of exercising discretion to authorize higher percentage volume measurement uncertainty levels if appropriate technical and economic justifications have been provided.".

SEC. 50102. OFFSHORE OIL AND GAS LEASING.

(a) LEASE SALES.—

(1) GULF OF AMERICA REGION.—

(A) IN GENERAL.—Notwithstanding the 2024–2029 National Outer Continental Shelf Oil and Gas Leasing Program (and any successor leasing program that does not satisfy the requirements of this section), in addition to lease sales which may be held under that program, and except within areas subject to existing oil and gas leasing moratoria, the Secretary of the Interior shall conduct a minimum of 30 region-wide oil and gas lease sales, in a manner consistent with the schedule described in subparagraph (B), in the region identified in the map depicting lease terms and economic conditions accompanying the final notice of sale of the Bureau of Ocean Energy Management entitled "Gulf of Mexico Outer Continental Shelf Region-Wide Oil and Gas Lease Sale 254" (85 Fed. Reg. 8010 (February 12, 2020)).

(B) TIMING REQUIREMENT.—Of the not fewer than 30 region-wide lease sales required under this paragraph, the Secretary of the Interior shall—

(i) hold not fewer than 1 lease sale in the region described in subparagraph (A) by December 15, 2025;

(ii) hold not fewer than 2 lease sales in that region in each of calendar years 2026 through 2039, 1 of which shall be held by March 15 of the applicable calendar year and 1 of which shall be held after March 15 but not later than August 15 of the applicable calendar year; and

(iii) hold not fewer than 1 lease sale in that region in calendar year 2040, which shall be held by March 15, 2040.

(2) ALASKA REGION.—

(A) IN GENERAL.—The Secretary of the Interior shall conduct a minimum of 6 offshore lease sales, in a manner consistent with the schedule described in subparagraph (B), in the Cook Inlet Planning Area as identified in the 2017–2022 Outer Continental Shelf Oil and Gas Leasing Proposed Final Program published on November 18, 2016, by the Bureau of Ocean Energy Management (as announced in the notice of availability of the Bureau of Ocean Energy Management entitled "Notice of Availability of the 2017–2022 Outer Continental Shelf Oil and Gas Leasing Proposed Final Program" (81 Fed. Reg. 84612 (November 23, 2016))).

(B) TIMING REQUIREMENT.—Of the not fewer than 6 lease sales required under this paragraph, the Secretary of the Interior shall hold not fewer than 1 lease sale in the area described in subparagraph (A) in each of calendar years 2026 through 2028, and in each of calendar years 2030 through 2032, by March 15 of the applicable calendar year.

(b) REQUIREMENTS.—

(1) TERMS AND STIPULATIONS FOR GULF OF AMERICA SALES.—In conducting lease sales under subsection (a)(1), the Secretary of the Interior—

(A) shall, subject to subparagraph (C), offer the same lease form, lease terms, economic conditions, and lease stipulations 4 through 9 as contained in the final notice of sale of the Bureau of Ocean Energy Management entitled "Gulf of Mexico Outer Continental Shelf Region-Wide Oil and Gas Lease Sale 254" (85 Fed. Reg. 8010 (February 12, 2020));

(B) may update lease stipulations 1 through 3 and 10 described in that final notice of sale to reflect current conditions for lease sales conducted under subsection (a)(1);

(C) shall set the royalty rate at not less than 12½ percent but not greater than 16⅔ percent; and

(D) shall, for a lease in water depths of 800 meters or deeper issued as a result of a sale, set the primary term for 10 years.

(2) TERMS AND STIPULATIONS FOR ALASKA REGION SALES.—

(A) IN GENERAL.—In conducting lease sales under subsection (a)(2), the Secretary of the Interior shall offer the same lease form, lease terms, economic conditions, and stipulations as contained in the final notice of sale of the Bureau of Ocean Energy Management entitled "Cook Inlet Planning Area Outer Continental Shelf Oil and Gas Lease Sale 244" (82 Fed. Reg. 23291 (May 22, 2017)).

(B) REVENUE SHARING.—Notwithstanding section 8(g) and section 9 of the Outer Continental Shelf Lands Act (43 U.S.C. 1337(g), 1338), and beginning in fiscal year 2034, of the bonuses, rents, royalties, and other revenues derived from lease sales conducted under subsection (a)(2)—

(i) 70 percent shall be paid to the State of Alaska; and

(ii) 30 percent shall be deposited in the Treasury and credited to miscellaneous receipts.

(3) AREA OFFERED FOR LEASE.—

(A) GULF OF AMERICA REGION.—For each offshore lease sale conducted under subsection (a)(1), the Secretary of the Interior shall—

(i) offer not fewer than 80,000,000 acres; or

(ii) if there are fewer than 80,000,000 acres that are unleased and available, offer all unleased and available acres.

(B) ALASKA REGION.—For each offshore lease sale conducted under subsection (a)(2), the Secretary of the Interior shall—

(i) offer not fewer than 1,000,000 acres; or

(ii) if there are fewer than 1,000,000 acres that are unleased and available, offer all unleased and available acres.

(c) OFFSHORE COMMINGLING.—The Secretary of the Interior shall approve a request of an operator to commingle oil or gas production from multiple reservoirs within a single wellbore completed on the outer Continental Shelf in the Gulf of America Region unless the Secretary of the Interior determines that conclusive evidence establishes that the commingling—

(1) could not be conducted by the operator in a safe manner; or

(2) would result in an ultimate recovery from the applicable reservoirs to be reduced in comparison to the expected recovery of those reservoirs if they had not been commingled.

(d) OFFSHORE OIL AND GAS ROYALTY RATE.—

(1) REPEAL.—Section 50261 of Public Law 117–169 (136 Stat. 2056) is repealed, and any provision of law amended or repealed by that section is restored or revived as if that section had not been enacted into law.

(2) ROYALTY RATE.—Section 8(a)(1) of the Outer Continental Shelf Lands Act (43 U.S.C. 1337(a)(1)) (as amended by paragraph (1)) is amended—

(A) in subparagraph (A), by striking "not less than 12½ per centum" and inserting "not less than 12½ percent, but not more than 16⅔ percent,";

(B) in subparagraph (C), by striking "not less than 12½ per centum" and inserting "not less than 12½ percent, but not more than 16⅔ percent,";

(C) in subparagraph (F), by striking "no less than 12½ per centum" and inserting "not less than 12½ percent, but not more than 16⅔ percent,"; and

(D) in subparagraph (H), by striking "no less than 12 and ½ per centum" and inserting "not less than 12½ percent, but not more than 16⅔ percent,".

(e) LIMITATIONS ON AMOUNT OF DISTRIBUTED QUALIFIED OUTER CONTINENTAL SHELF REVENUES.—Section 105(f)(1) of the Gulf of Mexico Energy Security Act of 2006 (43 U.S.C. 1331 note; Public Law 109–432) is amended—

(1) in subparagraph (B), by striking "and" at the end;

(2) in subparagraph (C), by striking "2055." and inserting "2024;"; and

(3) by adding at the end the following:

"(D) $650,000,000 for each of fiscal years 2025 through 2034; and

"(E) $500,000,000 for each of fiscal years 2035 through 2055.".

SEC. 50103. ROYALTIES ON EXTRACTED METHANE.

Section 50263 of Public Law 117–169 (30 U.S.C. 1727) is repealed.

SEC. 50104. ALASKA OIL AND GAS LEASING.

(a) DEFINITIONS.—In this section:

(1) COASTAL PLAIN.—The term "Coastal Plain" has the meaning given the term in section 20001(a) of Public Law 115–97 (16 U.S.C. 3143 note).

(2) OIL AND GAS PROGRAM.—The term "oil and gas program" means the oil and gas program established under section 20001(b)(2) of Public Law 115–97 (16 U.S.C. 3143 note).

(3) SECRETARY.—The term "Secretary" means the Secretary of the Interior, acting through the Bureau of Land Management.

(b) LEASE SALES REQUIRED.—

(1) IN GENERAL.—Subject to paragraph (3), in addition to the lease sales required under section 20001(c)(1)(A) of Public Law 115–97 (16 U.S.C. 3143 note), the Secretary shall conduct not fewer than 4 lease sales area-wide under the oil and gas program by not later than 10 years after the date of enactment of this Act.

(2) TERMS AND CONDITIONS.—In conducting lease sales under paragraph (1), the Secretary shall offer the same terms and conditions as contained in the record of decision described in the notice of availability of the Bureau of Land Management entitled "Notice of Availability of the Record of Decision for the Final Environmental Impact Statement for the Coastal Plain Oil and Gas Leasing Program, Alaska" (85 Fed. Reg. 51754 (August 21, 2020)).

(3) SALE ACREAGES; SCHEDULE.—

(A) ACREAGES.—In conducting the lease sales required under paragraph (1), the Secretary shall offer for lease under the oil and gas program—

(i) not fewer than 400,000 acres area-wide in each lease sale; and

(ii) those areas that have the highest potential for the discovery of hydrocarbons.

(B) SCHEDULE.—The Secretary shall offer—

(i) the initial lease sale under paragraph (1) not later than 1 year after the date of enactment of this Act;

(ii) a second lease sale under paragraph (1) not later than 3 years after the date of enactment of this Act;

(iii) a third lease sale under paragraph (1) not later than 5 years after the date of enactment of this Act; and

(iv) a fourth lease sale under paragraph (1) not later than 7 years after the date of enactment of this Act.

(4) RIGHTS-OF-WAY.—Section 20001(c)(2) of Public Law 115–97 (16 U.S.C. 3143 note) shall apply to leases awarded under this subsection.

(5) SURFACE DEVELOPMENT.—Section 20001(c)(3) of Public Law 115–97 (16 U.S.C. 3143 note) shall apply to leases awarded under this subsection.

(c) RECEIPTS.—Notwithstanding section 35 of the Mineral Leasing Act (30 U.S.C. 191) and section 20001(b)(5) of Public Law 115–97 (16 U.S.C. 3143 note), of the amount of adjusted bonus, rental, and royalty receipts derived from the oil and gas program and operations on the Coastal Plain pursuant to this section—

(1)(A) for each of fiscal years 2025 through 2033, 50 percent shall be paid to the State of Alaska; and

(B) for fiscal year 2034 and each fiscal year thereafter, 70 percent shall be paid to the State of Alaska; and

(2) the balance shall be deposited into the Treasury as miscellaneous receipts.

SEC. 50105. NATIONAL PETROLEUM RESERVE–ALASKA.

(a) DEFINITIONS.—In this section:

(1) NPR–A FINAL ENVIRONMENTAL IMPACT STATEMENT.—The term "NPR–A final environmental impact statement" means the final environmental impact statement published by the Bureau of Land Management entitled "National Petroleum Reserve in Alaska Integrated Activity Plan Final Environmental Impact Statement" and dated June 2020, including the errata sheet dated October 6, 2020, and excluding the errata sheet dated September 20, 2022.

(2) NPR–A RECORD OF DECISION.—The term "NPR–A record of decision" means the record of decision published by the Bureau of Land Management entitled "National Petroleum Reserve in Alaska Integrated Activity Plan Record of Decision" and dated December 2020.

(3) PROGRAM.—The term "Program" means the competitive oil and gas leasing, exploration, development, and production program established under section 107 of the Naval Petroleum Reserves Production Act of 1976 (42 U.S.C. 6506a).

(4) SECRETARY.—The term "Secretary" means the Secretary of the Interior.

(b) RESTORATION OF NPR–A OIL AND GAS LEASING PROGRAM.—Effective beginning on the date of enactment of this Act, the Secretary shall expeditiously restore and resume oil and gas lease sales under the Program for domestic energy production and Federal revenue in the areas designated for oil and gas leasing as described in the NPR–A final environmental impact statement and the NPR–A record of decision.

(c) RESUMPTION OF NPR–A LEASE SALES.—

(1) IN GENERAL.—Subject to paragraph (2), the Secretary shall conduct not fewer than 5 lease sales under the Program by not later than 10 years after the date of enactment of this Act.

(2) SALES ACREAGES; SCHEDULE.—

(A) ACREAGES.—In conducting the lease sales required under paragraph (1), the Secretary shall offer not fewer than 4,000,000 acres in each lease sale.

(B) SCHEDULE.—The Secretary shall offer—

(i) an initial lease sale under paragraph (1) not later than 1 year after the date of enactment of this Act; and

(ii) an additional lease sale under paragraph (1) not later than every 2 years after the date of enactment of this Act.

(d) TERMS AND STIPULATIONS FOR NPR–A LEASE SALES.—In conducting lease sales under subsection (c), the Secretary shall offer the same lease form, lease terms, economic conditions, and stipulations as described in the NPR–A final environmental impact statement and the NPR–A record of decision.

(e) RECEIPTS.—Section 107(l) of the Naval Petroleum Reserves Production Act of 1976 (42 U.S.C. 6506a(l)) is amended—

(1) by striking "All receipts from" and inserting the following:

"(1) IN GENERAL.—Except as provided in paragraph (2), all receipts from"; and

(2) by adding at the end the following:

"(2) PERCENT SHARE FOR FISCAL YEAR 2034 AND THEREAFTER.—Beginning in fiscal year 2034, of the receipts from sales, rentals, bonuses, and royalties on leases issued pursuant to this section after the date of enactment of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress)—

"(A) 70 percent shall be paid to the State of Alaska; and

"(B) 30 percent shall be paid into the Treasury of the United States.".

Subtitle B—Mining

SEC. 50201. COAL LEASING.

(a) DEFINITIONS.—In this section:

(1) COAL LEASE.—The term "coal lease" means a lease entered into by the United States as lessor, through the Bureau of Land Management, and an applicant on Bureau of Land Management Form 3400-012 (or a successor form that contains the terms of a coal lease).

(2) QUALIFIED APPLICATION.—The term "qualified application" means an application for a coal lease pending as of the date of enactment of this Act or submitted within 90 days thereafter under the lease by application program administered by the Bureau of Land Management pursuant to the Mineral Leasing Act (30 U.S.C. 181 et seq.) for which any required environmental review has commenced or the Director of the Bureau of Land Management determines can commence within 90 days after receiving the application.

(b) COAL LEASING ACTIVITIES.—Not later than 90 days after the date of enactment of this Act, the Secretary of the Interior—

(1) shall—

(A) with respect to each qualified application—

(i) if not previously published for public comment, publish any required environmental review;

(ii) establish the fair market value of the applicable coal tract;

(iii) hold a lease sale with respect to the applicable coal tract; and

(iv) identify the highest bidder at or above the fair market value and take all other intermediate actions necessary to identify the winning bidder and grant the qualified application; and

(2) may—

(A) with respect to a previously issued coal lease, grant any additional approvals of the Department of the Interior required for mining activities to commence; and

(B) after completing the actions required by clauses (i) through (iv) of paragraph (1)(A), grant the qualified application and issue the applicable lease to the person that submitted the qualified application if that person submitted the winning bid in the lease sale held under clause (iii) of paragraph (1)(A).

SEC. 50202. COAL ROYALTY.

(a) RATE.—Section 7(a) of the Mineral Leasing Act (30 U.S.C. 207(a)) is amended, in the fourth sentence, by striking "12½ per centum" and inserting "12½ percent, except such amount shall be not more than 7 percent during the period that begins on the date of enactment of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress) and ends September 30, 2034,".

(b) APPLICABILITY TO EXISTING LEASES.—The amendment made by subsection (a) shall apply to a coal lease—

(1) issued under section 2 of the Mineral Leasing Act (30 U.S.C. 201) before, on, or after the date of the enactment of this Act; and

(2) that has not been terminated.

(c) ADVANCE ROYALTIES.—With respect to a lease issued under section 2 of the Mineral Leasing Act (30 U.S.C. 201) for which the lessee has paid advance royalties under section 7(b) of that Act (30 U.S.C. 207(b)), the Secretary of the Interior shall provide to the lessee a credit for the difference between the amount paid by the lessee in advance royalties for the lease before the date of the enactment of this Act and the amount the lessee would have been required to pay if the amendment made by subsection

(a) had been made before the lessee paid advance royalties for the lease.

SEC. 50203. LEASES FOR KNOWN RECOVERABLE COAL RESOURCES.

Notwithstanding section 2(a)(3)(A) of the Mineral Leasing Act (30 U.S.C. 201(a)(3)(A)) and section 202(a) of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1712(a)), not later than 90 days after the date of enactment of this Act, the Secretary of the Interior shall make available for lease known recoverable coal resources of not less than 4,000,000 additional acres on Federal land located in the 48 contiguous States and Alaska subject to the jurisdiction of the Secretary, but which shall not include any Federal land within—

(1) a National Monument;

(2) a National Recreation Area;

(3) a component of the National Wilderness Preservation System;

(4) a component of the National Wild and Scenic Rivers System;

(5) a component of the National Trails System;

(6) a National Conservation Area;

(7) a unit of the National Wildlife Refuge System;

(8) a unit of the National Fish Hatchery System; or

(9) a unit of the National Park System.

SEC. 50204. AUTHORIZATION TO MINE FEDERAL COAL.

(a) AUTHORIZATION.—In order to provide access to coal reserves in adjacent State or private land that without an authorization could not be mined economically, Federal coal reserves located in Federal land subject to a mining plan previously approved by the Secretary of the Interior as of the date of enactment of this Act and adjacent to coal reserves in adjacent State or private land are authorized to be mined.

(b) REQUIREMENT.—Not later than 90 days after the date of enactment of this Act, the Secretary of the Interior shall, without substantial modification, take such steps as are necessary to authorize the mining of Federal land described in subsection (a).

(c) NEPA.—Nothing in this section shall prevent a review under the National Environmental Policy Act of 1969 (42 U.S.C. 4321 et seq.).

Subtitle C—Lands

SEC. 50301. TIMBER SALES AND LONG-TERM CONTRACTING FOR THE FOREST SERVICE AND THE BUREAU OF LAND MANAGEMENT.

(a) FOREST SERVICE.—

(1) DEFINITIONS.—In this subsection:

(A) FOREST PLAN.—The term "forest plan" means a land and resource management plan prepared by the Secretary for a unit of the National Forest System pursuant to section 6 of the Forest and Rangeland Renewable Resources Planning Act of 1974 (16 U.S.C. 1604).

(B) NATIONAL FOREST SYSTEM.—

(i) IN GENERAL.—The term "National Forest System" means land of the National Forest System (as defined in section 11(a) of the Forest and Rangeland

Renewable Resources Planning Act of 1974 (16 U.S.C. 1609(a))) administered by the Secretary.

(ii) EXCLUSIONS.—The term "National Forest System" does not include any forest reserve not created from the public domain.

(C) SECRETARY.—The term "Secretary" means the Secretary of Agriculture, acting through the Chief of the Forest Service.

(2) TIMBER SALES ON PUBLIC DOMAIN FOREST RESERVES.—

(A) IN GENERAL.—For each of fiscal years 2026 through 2034, the Secretary shall sell timber annually on National Forest System land in a total quantity that is not less than 250,000,000 board-feet greater than the quantity of board-feet sold in the previous fiscal year.

(B) LIMITATION.—The timber sales under subparagraph (A) shall be subject to the maximum allowable sale quantity of timber or the projected timber sale quantity under the applicable forest plan in effect on the date of enactment of this Act.

(3) LONG-TERM CONTRACTING FOR THE FOREST SERVICE.—

(A) LONG-TERM CONTRACTING.—For the period of fiscal years 2025 through 2034, the Secretary shall enter into not fewer than 40 long-term timber sale contracts with private persons or other public or private entities under subsection (a) of section 14 of the National Forest Management Act of 1976 (16 U.S.C. 472a) for the sale of national forest materials (as defined in subsection (e)(1) of that section) in the National Forest System.

(B) CONTRACT LENGTH.—The period of a timber sale contract entered into to meet the requirement under subparagraph (A) shall be not less than 20 years, with options for extensions or renewals, as determined by the Secretary.

(C) RECEIPTS.—Any monies derived from a timber sale contract entered into to meet the requirements under subparagraphs (A) and (B) shall be deposited in the general fund of the Treasury.

(b) BUREAU OF LAND MANAGEMENT.—

(1) DEFINITIONS.—In this subsection:

(A) PUBLIC LANDS.—The term "public lands" has the meaning given the term in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702).

(B) RESOURCE MANAGEMENT PLAN.—The term "resource management plan" means a land use plan prepared for public lands under section 202 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1712).

(C) SECRETARY.—The term "Secretary" means the Secretary of the Interior, acting through the Director of the Bureau of Land Management.

(2) TIMBER SALES ON PUBLIC LANDS.—

(A) IN GENERAL.—For each of fiscal years 2026 through 2034, the Secretary shall sell timber annually on public lands in a total quantity that is not less than 20,000,000 board-feet greater than the quantity of board-feet sold in the previous fiscal year.

(B) LIMITATION.—The timber sales under subparagraph (A) shall be subject to the applicable resource management plan in effect on the date of enactment of this Act.

(3) LONG-TERM CONTRACTING FOR THE BUREAU OF LAND MANAGEMENT.—

(A) LONG-TERM CONTRACTING.—For the period of fiscal years 2025 through 2034, the Secretary shall enter into not fewer than 5 long-term contracts with private persons or other public or private entities under section 1 of the Act of July 31, 1947 (commonly known as the "Materials Act of 1947") (61 Stat. 681, chapter 406; 30 U.S.C. 601), for the disposal of vegetative materials described in that section on public lands.

(B) CONTRACT LENGTH.—The period of a contract entered into to meet the requirement under subparagraph (A) shall be not less than 20 years, with options for extensions or renewals, as determined by the Secretary.

(C) RECEIPTS.—Any monies derived from a contract entered into to meet the requirements under subparagraphs (A) and (B) shall be deposited in the general fund of the Treasury.

SEC. 50302. RENEWABLE ENERGY FEES ON FEDERAL LAND.

(a) DEFINITIONS.—In this section:

(1) ANNUAL ADJUSTMENT FACTOR.—The term "Annual Adjustment Factor" means 3 percent.

(2) ENCUMBRANCE FACTOR.—The term "Encumbrance Factor" means—

(A) 100 percent for a solar energy generation facility; and

(B) an amount determined by the Secretary, but not less than 10 percent for a wind energy generation facility.

(3) NATIONAL FOREST SYSTEM.—

(A) IN GENERAL.—The term "National Forest System" means land of the National Forest System (as defined in section 11(a) of the Forest and Rangeland Renewable Resources Planning Act of 1974 (16 U.S.C. 1609(a))) administered by the Secretary of Agriculture.

(B) EXCLUSION.—The term "National Forest System" does not include any forest reserve not created from the public domain.

(4) PER-ACRE RATE.—The term "Per-Acre Rate", with respect to a right-of-way, means the average of the per-acre pastureland rental rates published in the Cash Rents Survey by the National Agricultural Statistics Service for the State in which the right-of-way is located over the 5 calendar-year period preceding the issuance or renewal of the right-of-way.

(5) PROJECT.—The term "project" means a system described in section 2801.9(a)(4) of title 43, Code of Federal Regulations (as in effect on the date of enactment of this Act).

(6) PUBLIC LAND.—The term "public land" means—

(A) public lands (as defined in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702)); and

(B) National Forest System land.

(7) RENEWABLE ENERGY PROJECT.—The term "renewable energy project" means a project located on public land that uses wind or solar energy to generate energy.

(8) RIGHT-OF-WAY.—The term "right-of-way" has the meaning given the term in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702).

(9) SECRETARY.—The term "Secretary" means—

(A) the Secretary of the Interior, with respect to land controlled or administered by the Secretary of the Interior; and

(B) the Secretary of Agriculture, with respect to National Forest System land.

(b) ACREAGE RENT FOR WIND AND SOLAR RIGHTS-OF-WAY.—

(1) IN GENERAL.—Pursuant to section 504(g) of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1764(g)), the Secretary shall, subject to paragraph (3) and not later than January 1 of each calendar year, collect from the holder of a right-of-way for a renewable energy project an acreage rent in an amount determined by the equation described in paragraph (2).

(2) CALCULATION OF ACREAGE RENT RATE.—

(A) EQUATION.—The amount of an acreage rent collected under paragraph (1) shall be determined using the following equation: Acreage rent = $A \times B \times ((1 + C)^D)$).

(B) DEFINITIONS.—For purposes of the equation described in subparagraph (A):

(i) The letter "A" means the Per-Acre Rate.

(ii) The letter "B" means the Encumbrance Factor.

(iii) The letter "C" means the Annual Adjustment Factor.

(iv) The letter "D" means the year in the term of the right-of-way.

(3) PAYMENT UNTIL PRODUCTION.—The holder of a right-of-way for a renewable energy project shall pay an acreage rent collected under paragraph (1) until the date on which energy generation begins.

(c) CAPACITY FEES.—

(1) IN GENERAL.—The Secretary shall, subject to paragraph (3), annually collect a capacity fee from the holder of a right-of-way for a renewable energy project based on the amount described in paragraph (2).

(2) CALCULATION OF CAPACITY FEE.—The amount of a capacity fee collected under paragraph (1) shall be equal to the greater of—

(A) an amount equal to the acreage rent described in subsection (b); and

(B) 3.9 percent of the gross proceeds from the sale of electricity produced by the renewable energy project.

(3) MULTIPLE-USE REDUCTION FACTOR.—

(A) APPLICATION.—The holder of a right-of-way for a wind energy generation project may request that the Secretary apply a multiple-use reduction factor of 10-percent to the amount of a capacity fee determined under paragraph (2) by submitting to the Secretary an application at such time, in such manner, and containing such information as the Secretary may require.

(B) APPROVAL.—The Secretary may approve an application submitted under subparagraph (A) only if not less than 25 percent of the land within the area of the right-of-way is authorized for use, occupancy, or development with respect to an activity other than the generation of wind energy for the entirety of the year in which the capacity fee is collected.

(C) LATE DETERMINATION.—

(i) IN GENERAL.—If the Secretary approves an application under subparagraph (B) for a wind energy generation project after the date on which the holder of the right-of-way for the project begins paying a capacity fee, the Secretary shall apply the multiple-use reduction factor described in subparagraph (A) to the capacity fee for the first year beginning after the date of approval and each year thereafter for the period during which the right-of-way remains in effect.

(ii) REFUND.—The Secretary may not refund the holder of a right-of-way for the difference in the amount of a capacity fee paid in a previous year.

(d) LATE PAYMENT FEE; TERMINATION.—

(1) IN GENERAL.—The Secretary may charge the holder of a right-of-way for a renewable energy project a late payment fee if the Secretary does not receive payment for the acreage rent under subsection (b) or the capacity fee under subsection (c) by the date that is 15 days after the date on which the payment was due.

(2) TERMINATION OF RIGHT-OF-WAY.—The Secretary may terminate a right-of-way for a renewable energy project if the Secretary does not receive payment for the acreage rent under subsection (b) or the capacity fee under subsection (c) by the date that is 90 days after the date on which the payment was due.

SEC. 50303. RENEWABLE ENERGY REVENUE SHARING.

(a) DEFINITIONS.—In this section:

(1) COUNTY.—The term "county" includes a parish, township, borough, and any other similar, independent unit of local government.

(2) COVERED LAND.—The term "covered land" means land that is—

(A) public land administered by the Secretary; and

(B) not excluded from the development of solar or wind energy under—

(i) a land use plan; or

(ii) other Federal law.

(3) NATIONAL FOREST SYSTEM.—

(A) IN GENERAL.—The term "National Forest System" means land of the National Forest System (as defined in section 11(a) of the Forest and Rangeland Renewable Resources Planning Act of 1974 (16 U.S.C. 1609(a))) administered by the Secretary of Agriculture.

(B) EXCLUSION.—The term "National Forest System" does not include any forest reserve not created from the public domain.

(4) PUBLIC LAND.—The term "public land" means—

(A) public lands (as defined in section 103 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1702)); and

(B) National Forest System land.

(5) RENEWABLE ENERGY PROJECT.—The term "renewable energy project" means a system described in section 2801.9(a)(4) of title 43, Code of Federal Regulations (as in effect on the date of enactment of this Act), located on covered land that uses wind or solar energy to generate energy.

(6) SECRETARY.—The term "Secretary" means—

(A) the Secretary of the Interior, with respect to land controlled or administered by the Secretary of the Interior; and

(B) the Secretary of Agriculture, with respect to National Forest System land.

(b) DISPOSITION OF REVENUE.—

(1) DISPOSITION OF REVENUES.—Beginning on January 1, 2026, the amounts collected from a renewable energy project as bonus bids, rentals, fees, or other payments under a right-of-way, permit, lease, or other authorization shall—

(A) be deposited in the general fund of the Treasury; and

(B) without further appropriation or fiscal year limitation, be allocated as follows:

(i) 25 percent shall be paid from amounts in the general fund of the Treasury to the State within the boundaries of which the revenue is derived.

(ii) 25 percent shall be paid from amounts in the general fund of the Treasury to each county in a State within the boundaries of which the revenue is derived, to be allocated among each applicable county based on the percentage of county land from which the revenue is derived.

(2) PAYMENTS TO STATES AND COUNTIES.—

(A) IN GENERAL.—Amounts paid to States and counties under paragraph (1) shall be used in accordance with the requirements of section 35 of the Mineral Leasing Act (30 U.S.C. 191).

(B) PAYMENTS IN LIEU OF TAXES.—A payment to a county under paragraph (1) shall be in addition to a payment in lieu of taxes received by the county under chapter 69 of title 31, United States Code.

(C) TIMING.—The amounts required to be paid under paragraph (1)(B) for an applicable fiscal year shall be made available in the fiscal year that immediately follows the fiscal year for which the amounts were collected.

SEC. 50304. RESCISSION OF NATIONAL PARK SERVICE AND BUREAU OF LAND MANAGEMENT FUNDS.

There are rescinded the unobligated balances of amounts made available by the following sections of Public Law 117–169 (commonly known as the "Inflation Reduction Act of 2022") (136 Stat. 1818):

(1) Section 50221 (136 Stat. 2052).

(2) Section 50222 (136 Stat. 2052).

(3) Section 50223 (136 Stat. 2052).

SEC. 50305. CELEBRATING AMERICA'S 250TH ANNIVERSARY.

In addition to amounts otherwise available, there is appropriated to the Secretary of the Interior (acting through the Director of the National Park Service) for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $150,000,000 for events, celebrations, and activities surrounding the observance and commemoration of the 250th anniversary of the founding of the United States, to remain available through fiscal year 2028.

Subtitle D—Energy

SEC. 50401. STRATEGIC PETROLEUM RESERVE.

(a) ENERGY POLICY AND CONSERVATION ACT DEFINITIONS.—In this section, the terms "related facility", "storage facility", and "Strategic Petroleum Reserve" have the meanings given those terms in section 152 of the Energy Policy and Conservation Act (42 U.S.C. 6232).

(b) APPROPRIATIONS.—In addition to amounts otherwise available, there is appropriated to the Department of Energy for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029—

(1) $218,000,000 for maintenance of, including repairs to, storage facilities and related facilities of the Strategic Petroleum Reserve; and

(2) $171,000,000 to acquire, by purchase, petroleum products for storage in the Strategic Petroleum Reserve.

(c) REPEAL OF STRATEGIC PETROLEUM RESERVE DRAWDOWN AND SALE MANDATE.—Section 20003 of Public Law 115–97 (42 U.S.C. 6241 note) is repealed.

SEC. 50402. REPEALS; RESCISSIONS.

(a) REPEAL AND RESCISSION.—Section 50142 of Public Law 117–169 (136 Stat. 2044) (commonly known as the "Inflation Reduction Act of 2022") is repealed and the unobligated balance of amounts made available under that section (as in effect on the day before the date of enactment of this Act) is rescinded.

(b) RESCISSIONS.—

(1) IN GENERAL.—The unobligated balances of amounts made available under the sections described in paragraph (2) are rescinded.

(2) SECTIONS DESCRIBED.—The sections referred to in paragraph (1) are the following sections of Public Law 117–169 (commonly known as the "Inflation Reduction Act of 2022"):

(A) Section 50123 (42 U.S.C. 18795b).

(B) Section 50141 (136 Stat. 2042).

(C) Section 50144 (136 Stat. 2044).

(D) Section 50145 (136 Stat. 2045).

(E) Section 50151 (42 U.S.C. 18715).

(F) Section 50152 (42 U.S.C. 18715a).

(G) Section 50153 (42 U.S.C. 18715b).

(H) Section 50161 (42 U.S.C. 17113b).

SEC. 50403. ENERGY DOMINANCE FINANCING.

(a) IN GENERAL.—Section 1706 of the Energy Policy Act of 2005 (42 U.S.C. 16517) is amended—

(1) in subsection (a)—

(A) in paragraph (1), by striking "or" at the end;

(B) in paragraph (2), by striking "avoid" and all that follows through the period at the end and inserting "increase capacity or output; or"; and

(C) by adding at the end the following:

"(3) support or enable the provision of known or forecastable electric supply at time intervals necessary to maintain or enhance grid reliability or other system adequacy needs.";

(2) by striking subsection (c);

(3) by redesignating subsections (d) through (f) as subsections (c) through (e), respectively;

(4) in subsection (c) (as so redesignated)—

(A) in paragraph (1), by adding "and" at the end;

(B) by striking paragraph (2); and

(C) by redesignating paragraph (3) as paragraph (2);

(5) in subsection (e) (as so redesignated), by striking "for—" in the matter preceding paragraph (1) and all that follows through the period at the end of paragraph (2) and inserting "for enabling the identification, leasing, development, production, processing, transportation, transmission, refining, and generation needed for energy and critical minerals."; and

(6) by adding at the end the following:

"(f) FUNDING.—

"(1) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Secretary for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $1,000,000,000, to remain available through September 30, 2028, to carry out activities under this section.

"(2) ADMINISTRATIVE COSTS.—Of the amount made available under paragraph (1), the Secretary shall use not more than 3 percent for administrative expenses.".

(b) COMMITMENT AUTHORITY.—Section 50144(b) of Public Law 117–169 (commonly known as the "Inflation Reduction Act of 2022") (136 Stat. 2045) is amended by striking "2026" and inserting "2028".

SEC. 50404. TRANSFORMATIONAL ARTIFICIAL INTELLIGENCE MODELS.

(a) DEFINITIONS.—In this section:

(1) AMERICAN SCIENCE CLOUD.—The term "American science cloud" means a system of United States government, academic, and private sector programs and infrastructures utilizing cloud computing technologies to facilitate and support scientific research, data sharing, and computational analysis across various disciplines while ensuring compliance with applicable legal, regulatory, and privacy standards.

(2) ARTIFICIAL INTELLIGENCE.—The term "artificial intelligence" has the meaning given the term in section 5002 of the National Artificial Intelligence Initiative Act of 2020 (15 U.S.C. 9401).

(b) TRANSFORMATIONAL MODELS.—The Secretary of Energy shall—

(1) mobilize National Laboratories to partner with industry sectors within the United States to curate the scientific data of the Department of Energy across the National Laboratory complex so that the data is structured, cleaned, and preprocessed in a way that makes it suitable for use in artificial intelligence and machine learning models; and

(2) initiate seed efforts for self-improving artificial intelligence models for science and engineering powered by the data described in paragraph (1).

(c) USES.—

(1) MICROELECTRONICS.—The curated data described in subsection (b)(1) may be used to rapidly develop next-generation microelectronics that have greater capabilities beyond Moore's law while requiring lower energy consumption.

(2) NEW ENERGY TECHNOLOGIES.—The artificial intelligence models developed under subsection (b)(2) shall be provided to the scientific community through the American science cloud to accelerate innovation in discovery science and engineering for new energy technologies.

(d) APPROPRIATIONS.—There is appropriated, out of any funds in the Treasury not otherwise appropriated, $150,000,000, to remain available through September 30, 2026, to carry out this section.

Subtitle E—Water

SEC. 50501. WATER CONVEYANCE AND SURFACE WATER STORAGE ENHANCEMENT.

In addition to amounts otherwise available, there is appropriated to the Secretary of the Interior, acting through the Commissioner of Reclamation, for fiscal year 2025, out of any funds in the Treasury not otherwise appropriated, $1,000,000,000, to remain available through September 30, 2034, for construction and associated activities that restore or increase the capacity or use of existing conveyance facilities constructed by the Bureau of Reclamation or for construction and associated activities that increase the capacity of existing Bureau of Reclamation surface water storage facilities, in a manner as determined by the Secretary of the Interior, acting through the Commissioner of Reclamation: *Provided,* That, for the purposes of section 203 of the Reclamation Reform Act of 1982 (43 U.S.C. 390cc) or section 3404(a) of the Reclamation Projects Authorization and Adjustment Act of 1992 (Public Law 102–575; 106 Stat. 4708), a contract or agreement entered into pursuant to this section shall not be treated as a new or amended contract: *Provided further,* That none of the funds provided under this section shall be reimbursable or subject to matching or cost-sharing requirements.

TITLE VI—COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

SEC. 60001. RESCISSION OF FUNDING FOR CLEAN HEAVY-DUTY VEHICLES.

The unobligated balances of amounts made available to carry out section 132 of the Clean Air Act (42 U.S.C. 7432) are rescinded.

SEC. 60002. REPEAL OF GREENHOUSE GAS REDUCTION FUND.

Section 134 of the Clean Air Act (42 U.S.C. 7434) is repealed and the unobligated balances of amounts made available to carry out that section (as in effect on the day before the date of enactment of this Act) are rescinded.

SEC. 60003. RESCISSION OF FUNDING FOR DIESEL EMISSIONS REDUCTIONS.

The unobligated balances of amounts made available to carry out section 60104 of Public Law 117–169 (136 Stat. 2067) are rescinded.

SEC. 60004. RESCISSION OF FUNDING TO ADDRESS AIR POLLUTION.

The unobligated balances of amounts made available to carry out section 60105 of Public Law 117–169 (136 Stat. 2067) are rescinded.

SEC. 60005. RESCISSION OF FUNDING TO ADDRESS AIR POLLUTION AT SCHOOLS.

The unobligated balances of amounts made available to carry out section 60106 of Public Law 117–169 (136 Stat. 2069) are rescinded.

SEC. 60006. RESCISSION OF FUNDING FOR THE LOW EMISSIONS ELECTRICITY PROGRAM.

The unobligated balances of amounts made available to carry out section 135 of the Clean Air Act (42 U.S.C. 7435) are rescinded.

SEC. 60007. RESCISSION OF FUNDING FOR SECTION 211(O) OF THE CLEAN AIR ACT.

The unobligated balances of amounts made available to carry out section 60108 of Public Law 117–169 (136 Stat. 2070) are rescinded.

SEC. 60008. RESCISSION OF FUNDING FOR IMPLEMENTATION OF THE AMERICAN INNOVATION AND MANUFACTURING ACT.

The unobligated balances of amounts made available to carry out section 60109 of Public Law 117–169 (136 Stat. 2071) are rescinded.

SEC. 60009. RESCISSION OF FUNDING FOR ENFORCEMENT TECHNOLOGY AND PUBLIC INFORMATION.

The unobligated balances of amounts made available to carry out section 60110 of Public Law 117–169 (136 Stat. 2071) are rescinded.

SEC. 60010. RESCISSION OF FUNDING FOR GREENHOUSE GAS CORPORATE REPORTING.

The unobligated balances of amounts made available to carry out section 60111 of Public Law 117–169 (136 Stat. 2072) are rescinded.

SEC. 60011. RESCISSION OF FUNDING FOR ENVIRONMENTAL PRODUCT DECLARATION ASSISTANCE.

The unobligated balances of amounts made available to carry out section 60112 of Public Law 117–169 (42 U.S.C. 4321 note; 136 Stat. 2072) are rescinded.

SEC. 60012. RESCISSION OF FUNDING FOR METHANE EMISSIONS AND WASTE REDUCTION INCENTIVE PROGRAM FOR PETROLEUM AND NATURAL GAS SYSTEMS.

(a) RESCISSION.—The unobligated balances of amounts made available to carry out subsections (a) and (b) of section 136 of the Clean Air Act (42 U.S.C. 7436) are rescinded.

(b) PERIOD.—Section 136(g) of the Clean Air Act (42 U.S.C. 7436(g)) is amended by striking "calendar year 2024" and inserting "calendar year 2034".

SEC. 60013. RESCISSION OF FUNDING FOR GREENHOUSE GAS AIR POLLUTION PLANS AND IMPLEMENTATION GRANTS.

The unobligated balances of amounts made available to carry out section 137 of the Clean Air Act (42 U.S.C. 7437) are rescinded.

SEC. 60014. RESCISSION OF FUNDING FOR ENVIRONMENTAL PROTECTION AGENCY EFFICIENT, ACCURATE, AND TIMELY REVIEWS.

The unobligated balances of amounts made available to carry out section 60115 of Public Law 117–169 (136 Stat. 2077) are rescinded.

SEC. 60015. RESCISSION OF FUNDING FOR LOW-EMBODIED CARBON LABELING FOR CONSTRUCTION MATERIALS.

The unobligated balances of amounts made available to carry out section 60116 of Public Law 117–169 (42 U.S.C. 4321 note; 136 Stat. 2077) are rescinded.

SEC. 60016. RESCISSION OF FUNDING FOR ENVIRONMENTAL AND CLIMATE JUSTICE BLOCK GRANTS.

The unobligated balances of amounts made available to carry out section 138 of the Clean Air Act (42 U.S.C. 7438) are rescinded.

SEC. 60017. RESCISSION OF FUNDING FOR ESA RECOVERY PLANS.

The unobligated balances of amounts made available to carry out section 60301 of Public Law 117–169 (136 Stat. 2079) are rescinded.

SEC. 60018. RESCISSION OF FUNDING FOR ENVIRONMENTAL AND CLIMATE DATA COLLECTION.

The unobligated balances of amounts made available to carry out section 60401 of Public Law 117–169 (136 Stat. 2079) are rescinded.

SEC. 60019. RESCISSION OF NEIGHBORHOOD ACCESS AND EQUITY GRANT PROGRAM.

The unobligated balances of amounts made available to carry out section 177 of title 23, United States Code, are rescinded.

SEC. 60020. RESCISSION OF FUNDING FOR FEDERAL BUILDING ASSISTANCE.

The unobligated balances of amounts made available to carry out section 60502 of Public Law 117–169 (136 Stat. 2083) are rescinded.

SEC. 60021. RESCISSION OF FUNDING FOR LOW-CARBON MATERIALS FOR FEDERAL BUILDINGS.

The unobligated balances of amounts made available to carry out section 60503 of Public Law 117–169 (136 Stat. 2083) are rescinded.

SEC. 60022. RESCISSION OF FUNDING FOR GSA EMERGING AND SUSTAINABLE TECHNOLOGIES.

The unobligated balances of amounts made available to carry out section 60504 of Public Law 117–169 (136 Stat. 2083) are rescinded.

SEC. 60023. RESCISSION OF ENVIRONMENTAL REVIEW IMPLEMENTATION FUNDS.

The unobligated balances of amounts made available to carry out section 178 of title 23, United States Code, are rescinded.

SEC. 60024. RESCISSION OF LOW-CARBON TRANSPORTATION MATERIALS GRANTS.

The unobligated balances of amounts made available to carry out section 179 of title 23, United States Code, are rescinded.

SEC. 60025. JOHN F. KENNEDY CENTER FOR THE PERFORMING ARTS.

(a) IN GENERAL.—In addition to amounts otherwise available, there is appropriated for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $256,657,000, to remain available until September 30, 2029, for necessary expenses for capital repair, restoration, maintenance backlog, and security structures of the building and site of the John F. Kennedy Center for the Performing Arts.

(b) ADMINISTRATIVE COSTS.—Of the amounts made available under subsection (a), not more than 3 percent may be used for administrative costs necessary to carry out this section.

SEC. 60026. PROJECT SPONSOR OPT-IN FEES FOR ENVIRONMENTAL REVIEWS.

Title I of the National Environmental Policy Act of 1969 (42 U.S.C. 4331 et seq.) is amended by adding at the end the following:

"SEC. 112. PROJECT SPONSOR OPT-IN FEES FOR ENVIRONMENTAL REVIEWS.

"(a) PROCESS.—

"(1) PROJECT SPONSOR.—A project sponsor that intends to pay a fee under this section for the preparation, or supervision of the preparation, of an environmental assessment or environmental impact statement for a project shall submit to the Council—

"(A) a description of the project; and

"(B) a declaration of whether the project sponsor intends to prepare the environmental assessment or environmental impact statement under section 107(f).

"(2) COUNCIL ON ENVIRONMENTAL QUALITY.—Not later than 15 days after the date on which the Council receives information described in paragraph (1) from a project sponsor, the Council shall provide to the project sponsor notice of the amount of the fee to be paid under this section, as determined under subsection (b).

"(3) PAYMENT OF FEE.—A project sponsor may pay a fee under this section after receipt of the notice described in paragraph (2).

"(4) DEADLINE FOR ENVIRONMENTAL REVIEWS FOR WHICH A FEE IS PAID.—Notwithstanding section 107(g)(1)—

"(A) an environmental assessment for which a fee is paid under this section shall be completed not later than 180 days after the date on which the fee is paid; and

"(B) an environmental impact statement for which a fee is paid under this section shall be completed not later than 1 year after the date of publication of the notice of intent to prepare the environmental impact statement.

"(b) FEE AMOUNT.—The amount of a fee under this section shall be—

"(1) 125 percent of the anticipated costs to prepare the environmental assessment or environmental impact statement; and

"(2) in the case of an environmental assessment or environmental impact statement to be prepared in whole or in part by a project sponsor under section 107(f), 125 percent of the anticipated costs to supervise preparation of, and, as applicable, prepare, the environmental assessment or environmental impact statement.".

TITLE VII—FINANCE

Subtitle A—Tax

SEC. 70001. REFERENCES TO THE INTERNAL REVENUE CODE OF 1986, ETC.

(a) REFERENCES.—Except as otherwise expressly provided, whenever in this title, an amendment or repeal is expressed in terms of an amendment to, or repeal of, a section or other provision, the reference shall be considered to be made to a section or other provision of the Internal Revenue Code of 1986.

(b) CERTAIN RULES REGARDING EFFECT OF RATE CHANGES NOT APPLICABLE.—Section 15 of the Internal Revenue Code of 1986 shall not apply to any change in rate of tax by reason of any provision of, or amendment made by, this title.

CHAPTER 1—PROVIDING PERMANENT TAX RELIEF FOR MIDDLE-CLASS FAMILIES AND WORKERS

SEC. 70101. EXTENSION AND ENHANCEMENT OF REDUCED RATES.

(a) IN GENERAL.—Section 1(j) is amended—

(1) in paragraph (1), by striking ", and before January 1, 2026", and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) INFLATION ADJUSTMENT.—Section 1(j)(3)(B)(i) is amended by inserting "solely for purposes of determining the dollar amounts at which any rate bracket higher than 12 percent ends and at which any rate bracket higher than 22 percent begins," before "subsection (f)(3)".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70102. EXTENSION AND ENHANCEMENT OF INCREASED STANDARD DEDUCTION.

(a) IN GENERAL.—Section 63(c)(7) is amended—

(1) by striking ", and before January 1, 2026" in the matter preceding subparagraph (A), and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) ADDITIONAL INCREASE IN STANDARD DEDUCTION.—Paragraph (7) of section 63(c) is amended—

(1) by striking "$18,000" both places it appears in subparagraphs (A)(i) and (B)(ii) and inserting "$23,625",

(2) by striking "$12,000" both places it appears in subparagraphs (A)(ii) and (B)(ii) and inserting "$15,750",

(3) by striking "2018" in subparagraph (B)(ii) and inserting "2025", and

(4) by striking "2017" in subparagraph (B)(ii)(II) and inserting "2024".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

SEC. 70103. TERMINATION OF DEDUCTION FOR PERSONAL EXEMPTIONS OTHER THAN TEMPORARY SENIOR DEDUCTION.

(a) IN GENERAL.—Section 151(d)(5) is amended—

(1) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017",

(2) by striking ", and before January 1, 2026", and

(3) by adding at the end the following new subparagraph:

"(C) DEDUCTION FOR SENIORS.—

"(i) IN GENERAL.—In the case of a taxable year beginning before January 1, 2029, there shall be allowed a deduction in an amount equal to $6,000 for each qualified individual with respect to the taxpayer.

"(ii) QUALIFIED INDIVIDUAL.—For purposes of clause (i), the term 'qualified individual' means—

"(I) the taxpayer, if the taxpayer has attained age 65 before the close of the taxable year, and

"(II) in the case of a joint return, the taxpayer's spouse, if such spouse has attained age 65 before the close of the taxable year.

"(iii) LIMITATION BASED ON MODIFIED ADJUSTED GROSS INCOME.—

"(I) IN GENERAL.—In the case of any taxpayer for any taxable year, the $6,000 amount in clause (i) shall be reduced (but not below zero) by 6 percent of so much of the taxpayer's modified adjusted gross income as exceeds $75,000 ($150,000 in the case of a joint return).

"(II) MODIFIED ADJUSTED GROSS INCOME.—For purposes of this clause, the term 'modified adjusted gross income' means the adjusted gross income of the taxpayer for the taxable year increased by any amount excluded from gross income under section 911, 931, or 933.

"(iv) SOCIAL SECURITY NUMBER REQUIRED.—

"(I) IN GENERAL.—Clause (i) shall not apply with respect to a qualified individual unless the taxpayer includes such qualified individual's social security number on the return of tax for the taxable year.

"(II) SOCIAL SECURITY NUMBER.—For purposes of subclause (I), the term 'social security number' has the meaning given such term in section 24(h)(7).

"(v) MARRIED INDIVIDUALS.—If the taxpayer is a married individual (within the meaning of section

7703), this subparagraph shall apply only if the taxpayer and the taxpayer's spouse file a joint return for the taxable year.".

(b) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2) is amended by striking "and" at the end of subparagraph (U), by striking the period at the end of subparagraph (V) and inserting ", and", and by inserting after subparagraph (V) the following new subparagraph:

"(W) an omission of a correct social security number required under section 151(d)(5)(C) (relating to deduction for seniors).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

SEC. 70104. EXTENSION AND ENHANCEMENT OF INCREASED CHILD TAX CREDIT.

(a) EXTENSION AND INCREASE OF EXPANDED CHILD TAX CREDIT.—Section 24(h) is amended—

(1) in paragraph (1), by striking ", and before January 1, 2026",

(2) in paragraph (2), by striking "$2,000" and inserting "$2,200", and

(3) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) SOCIAL SECURITY NUMBER REQUIRED.—Section 24(h)(7) is amended to read as follows:

"(7) SOCIAL SECURITY NUMBER REQUIRED.—

"(A) IN GENERAL.—No credit shall be allowed under this section to a taxpayer with respect to any qualifying child unless the taxpayer includes on the return of tax for the taxable year—

"(i) the taxpayer's social security number (or, in the case of a joint return, the social security number of at least 1 spouse), and

"(ii) the social security number of such qualifying child.

"(B) SOCIAL SECURITY NUMBER.—For purposes of this paragraph, the term 'social security number' means a social security number issued to an individual by the Social Security Administration, but only if the social security number is issued—

"(i) to a citizen of the United States or pursuant to subclause (I) (or that portion of subclause (III) that relates to subclause (I)) of section 205(c)(2)(B)(i) of the Social Security Act, and

"(ii) before the due date for such return.".

(c) INFLATION ADJUSTMENTS.—Section 24(i) is amended to read as follows:

"(i) INFLATION ADJUSTMENTS.—

"(1) MAXIMUM AMOUNT OF REFUNDABLE CREDIT.—In the case of a taxable year beginning after 2024, the $1,400 amount in subsection (h)(5) shall be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting '2017' for '2016' in subparagraph (A)(ii) thereof.

"(2) SPECIAL RULE FOR ADJUSTMENT OF CREDIT AMOUNT.—In the case of a taxable year beginning after 2025, the $2,200 amount in subsection (h)(2) shall be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting '2024' for '2016' in subparagraph (A)(ii) thereof.

"(3) ROUNDING.—If any increase under this subsection is not a multiple of $100, such increase shall be rounded to the next lowest multiple of $100.".

(d) CONFORMING AMENDMENT.—Section 24(h)(5) is amended to read as follows:

"(5) MAXIMUM AMOUNT OF REFUNDABLE CREDIT.—The amount determined under subsection (d)(1)(A) with respect to any qualifying child shall not exceed $1,400, and such subsection shall be applied without regard to paragraph (4) of this subsection.".

(e) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2)(I) is amended by striking "section 24(e)" and inserting "section 24".

(f) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

SEC. 70105. EXTENSION AND ENHANCEMENT OF DEDUCTION FOR QUALIFIED BUSINESS INCOME.

(a) INCREASE IN TAXABLE INCOME LIMITATION PHASE-IN AMOUNTS.—

(1) IN GENERAL.—Subparagraph (B) of section 199A(b)(3) is amended by striking "$50,000 ($100,000 in the case of a joint return)" each place it appears and inserting "$75,000 ($150,000 in the case of a joint return)".

(2) CONFORMING AMENDMENT.—Paragraph (3) of section 199A(d) is amended by striking "$50,000 ($100,000 in the case of a joint return)" each place it appears and inserting "$75,000 ($150,000 in the case of a joint return)".

(b) MINIMUM DEDUCTION FOR ACTIVE QUALIFIED BUSINESS INCOME.—

(1) IN GENERAL.—Subsection (i) of section 199A is amended to read as follows:

"(i) MINIMUM DEDUCTION FOR ACTIVE QUALIFIED BUSINESS INCOME.—

"(1) IN GENERAL.—In the case of an applicable taxpayer for any taxable year, the deduction allowed under subsection (a) for the taxable year shall be equal to the greater of—

"(A) the amount of such deduction determined without regard to this subsection, or

"(B) $400.

"(2) APPLICABLE TAXPAYER.—For purposes of this subsection—

"(A) IN GENERAL.—The term 'applicable taxpayer' means, with respect to any taxable year, a taxpayer whose aggregate qualified business income with respect to all active qualified trades or businesses of the taxpayer for such taxable year is at least $1,000.

"(B) ACTIVE QUALIFIED TRADE OR BUSINESS.—The term 'active qualified trade or business' means, with respect to any taxpayer for any taxable year, any qualified trade or business of the taxpayer in which the taxpayer materially participates (within the meaning of section 469(h)).

"(3) INFLATION ADJUSTMENT.—In the case of any taxable year beginning after 2026, the $400 amount in paragraph (1)(B) and the $1,000 amount in paragraph (2)(A) shall each be increased by an amount equal to —

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

If any increase under this paragraph is not a multiple of $5, such increase shall be rounded to the nearest multiple of $5.".

(2) CONFORMING AMENDMENT.—Section 199A(a) is amended by inserting "except as provided in subsection (i)," before "there".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70106. EXTENSION AND ENHANCEMENT OF INCREASED ESTATE AND GIFT TAX EXEMPTION AMOUNTS.

(a) IN GENERAL.—Section 2010(c)(3) is amended—

(1) in subparagraph (A) by striking "$5,000,000" and inserting "$15,000,000",

(2) in subparagraph (B)—

(A) in the matter preceding clause (i), by striking "2011" and inserting "2026", and

(B) in clause (ii), by striking "calendar year 2010" and inserting "calendar year 2025", and

(3) by striking subparagraph (C).

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to estates of decedents dying and gifts made after December 31, 2025.

SEC. 70107. EXTENSION OF INCREASED ALTERNATIVE MINIMUM TAX EXEMPTION AMOUNTS AND MODIFICATION OF PHASE-OUT THRESHOLDS.

(a) IN GENERAL.—Section 55(d)(4) is amended—

(1) in subparagraph (A), by striking ", and before January 1, 2026", and

(2) by striking "AND BEFORE 2026" in the heading.

(b) MODIFICATION OF INFLATION ADJUSTMENT.—Section 55(d)(4)(B) is amended—

(1) by striking "2018" and inserting "2018 (2026, in the case of the $1,000,000 amount in subparagraph (A)(ii)(I))", and

(2) by striking "determined by substituting 'calendar year 2017' for 'calendar year 2016' in subparagraph (A)(ii) thereof." and inserting "determined by substituting for 'calendar year 2016' in subparagraph (A)(ii) thereof—

"(1) 'calendar year 2017', in the case of the $109,400 amount in subparagraph (A)(i)(I) and the $70,300 amount in subparagraph (A)(i)(II), and

"(2) 'calendar year 2025', in the case of the $1,000,000 amount in subparagraph (A)(ii)(I).".

(c) MODIFICATION OF PHASEOUT AMOUNT.—Section 55(d)(4)(A)(ii) is amended by striking "and" at the end of subclause (II), and by adding at the end the following new subclause:

"(IV) by substituting '50 percent' for '25 percent', and".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70108. EXTENSION AND MODIFICATION OF LIMITATION ON DEDUCTION FOR QUALIFIED RESIDENCE INTEREST.

(a) IN GENERAL.—Section 163(h)(3)(F) is amended—

(1) in clause (i)—

(A) by striking ", and before January 1, 2026",

(B) by redesignating subclauses (III) and (IV) as subclauses (IV) and (V), respectively,

(C) by striking "subclause (III)" in subclause (V), as so redesignated, and inserting "subclause (IV)", and

(D) by inserting after subclause (II) the following new subclause:

"(III) MORTGAGE INSURANCE PREMIUMS TREATED AS INTEREST.—Clause (iv) of subparagraph (E) shall not apply.",

(2) by striking clause (ii) and redesignating clauses (iii) and (iv) as clauses (ii) and (iii), respectively, and

(3) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70109. EXTENSION AND MODIFICATION OF LIMITATION ON CASUALTY LOSS DEDUCTION.

(a) IN GENERAL.—Section 165(h)(5) is amended—

(1) in subparagraph (A), by striking ", and before January 1, 2026", and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) EXTENSION TO STATE DECLARED DISASTERS.—

(1) IN GENERAL.—Subparagraph (A) of section 165(h)(5), as amended by subsection (a), is further amended by striking "(i)(5))" and inserting "(i)(5)) or a State declared disaster".

(2) EXCEPTION RELATED TO PERSONAL CASUALTY GAINS.—Clause (i) of section 165(h)(5)(B) is amended by striking "(as so defined)" and inserting "(as so defined) or a State declared disaster".

(3) STATE DECLARED DISASTER.—Paragraph (5) of section 165(h) is amended by adding at the end the following new subparagraph:

"(C) STATE DECLARED DISASTER.—For purposes of this paragraph—

"(i) IN GENERAL.—The term 'State declared disaster' means, with respect to any State, any natural catastrophe (including any hurricane, tornado, storm, high water, wind-driven water, tidal wave, tsunami, earthquake, volcanic eruption, landslide, mudslide, snowstorm, or drought), or, regardless of cause, any fire, flood, or explosion, in any part of the State, which in the determination of the Governor of such State (or the Mayor, in the case of the District of Columbia) and the Secretary causes damage of sufficient severity and magnitude to warrant the application of the rules of this section.

"(ii) STATE.—The term 'State' includes the District of Columbia, the Commonwealth of Puerto Rico, the Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Mariana Islands.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70110. TERMINATION OF MISCELLANEOUS ITEMIZED DEDUCTIONS OTHER THAN EDUCATOR EXPENSES.

(a) IN GENERAL.—Section 67(g) is amended—

(1) by striking ", and before January 1, 2026", and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) DEDUCTION FOR EDUCATOR EXPENSES.—

(1) IN GENERAL.—Section 67(b) is amended by striking "and" at the end of paragraph (11), by striking the period at the end of paragraph (12) and inserting ", and", and by adding at the end the following new paragraph:

"(13) the deductions allowed by section 162 for educator expenses (as defined in subsection (g)).".

(2) INCLUSION OF COACHES AND CERTAIN NONATHLETIC INSTRUCTIONAL EQUIPMENT.—Section 67 is amended by redesignating subsection (g), as amended by this section, as subsection (h), and by inserting after subsection (f) the following new section:

"(g) EDUCATOR EXPENSES.—For purposes of subsection (b)(13), the term 'educator expenses' means expenses of a type which would be described in section 62(a)(2)(D) if—

"(1) such section were applied—

"(A) without regard to the dollar limitation,

"(B) without regard to '(other than nonathletic supplies for courses of instruction in health or physical education)' in clause (ii) thereof, and

"(C) by substituting 'as part of instructional activity' for 'in the classroom' in clause (ii) thereof, and

"(2) section 62(d)(1)(A) were applied by inserting ', interscholastic sports administrator or coach,' after 'counselor'.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70111. LIMITATION ON TAX BENEFIT OF ITEMIZED DEDUCTIONS.

(a) IN GENERAL.—Section 68 is amended to read as follows:

"(a) IN GENERAL.—In the case of an individual, the amount of the itemized deductions otherwise allowable for the taxable year (determined without regard to this section) shall be reduced by $\frac{2}{37}$ of the lesser of—

"(1) such amount of itemized deductions, or

"(2) so much of the taxable income of the taxpayer for the taxable year (determined without regard to this section and increased by such amount of itemized deductions) as exceeds the dollar amount at which the 37 percent rate bracket under section 1 begins with respect to the taxpayer.

"(b) COORDINATION WITH OTHER LIMITATIONS.—This section shall be applied after the application of any other limitation on the allowance of any itemized deduction.".

(b) LIMITATION NOT APPLICABLE TO DETERMINATION OF DEDUCTION FOR QUALIFIED BUSINESS INCOME.—

(1) IN GENERAL.—Section 199A(e)(1) is amended by inserting "without regard to section 68 and" after "shall be computed".

(2) PATRONS OF SPECIFIED AGRICULTURAL AND HORTICULTURAL COOPERATIVES.—Section 199A(g)(2)(B) is amended by inserting "section 68 or" after "without regard to".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70112. EXTENSION AND MODIFICATION OF QUALIFIED TRANSPORTATION FRINGE BENEFITS.

(a) IN GENERAL.—Section 132(f) is amended—

(1) by striking subparagraph (D) of paragraph (1),

(2) in paragraph (2), by inserting "and" at the end of subparagraph (A), by striking ", and" at the end of subparagraph (B) and inserting a period, and by striking subparagraph (C),

(3) by striking "(other than a qualified bicycle commuting reimbursement)" in paragraph (4),

(4) by striking subparagraph (F) of paragraph (5), and

(5) by striking paragraph (8).

(b) INFLATION ADJUSTMENT.—Clause (ii) of section 132(f)(6)(A) is amended by striking "1998" in clause (ii) and inserting "1997".

(c) COORDINATION WITH DISALLOWANCE OF CERTAIN EXPENSES.—Subsection (l) of section 274 is amended—

(1) by striking "BENEFITS.—" and all that follows through "No deduction" and inserting "BENEFITS.—No deduction", and

(2) by striking paragraph (2).

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70113. EXTENSION AND MODIFICATION OF LIMITATION ON DEDUCTION AND EXCLUSION FOR MOVING EXPENSES.

(a) EXTENSION OF LIMITATION ON DEDUCTION.—Section 217(k) is amended—

(1) by striking ", and before January 1, 2026", and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(b) ALLOWANCE OF DEDUCTION FOR MEMBERS OF THE INTELLIGENCE COMMUNITY.—Section 217(k), as amended by subsection (a), is further amended—

(1) by striking "2017.—Except in the case" and inserting "2017.—

"(1) IN GENERAL.—Except in the case", and

(2) by adding at the end the following new paragraph:

"(2) MEMBERS OF THE INTELLIGENCE COMMUNITY.—An employee or new appointee of the intelligence community (as defined in section 3 of the National Security Act of 1947 (50 U.S.C. 3003)) (other than a member of the Armed Forces of the United States) who moves pursuant to a change in assignment which requires relocation shall be treated for purposes of this section in the same manner as an individual to whom subsection (g) applies.".

(c) EXTENSION OF LIMITATION ON EXCLUSION.—Section 132(g)(2) is amended—

(1) by striking ", and before January 1, 2026", and

(2) by striking "2018 THROUGH 2025" in the heading and inserting "BEGINNING AFTER 2017".

(d) ALLOWANCE OF EXCLUSION FOR MEMBERS OF THE INTELLIGENCE COMMUNITY.—Section 132(g)(2) of the Internal Revenue Code of 1986 is amended by inserting ", or an employee or new appointee of the intelligence community (as defined in section 3 of the National Security Act of 1947 (50 U.S.C. 3003)) (other than a member of the Armed Forces of the United States) who moves pursuant to a change in assignment that requires relocation" after "change of station".

(e) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70114. EXTENSION AND MODIFICATION OF LIMITATION ON WAGERING LOSSES.

(a) IN GENERAL.—Section 165 is amended by striking subsection (d) and inserting the following:

"(d) WAGERING LOSSES.—

"(1) IN GENERAL.—For purposes of losses from wagering transactions, the amount allowed as a deduction for any taxable year—

"(A) shall be equal to 90 percent of the amount of such losses during such taxable year, and

"(B) shall be allowed only to the extent of the gains from such transactions during such taxable year.

"(2) SPECIAL RULE.—For purposes of paragraph (1), the term 'losses from wagering transactions' includes any deduction otherwise allowable under this chapter incurred in carrying on any wagering transaction.".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70115. EXTENSION AND ENHANCEMENT OF INCREASED LIMITATION ON CONTRIBUTIONS TO ABLE ACCOUNTS.

(a) IN GENERAL.—Section 529A(b)(2)(B) is amended—

(1) in clause (i), by inserting "(determined by substituting '1996' for '1997' in paragraph (2)(B) thereof)" after "section 2503(b)", and

(2) in clause (ii), by striking "before January 1, 2026".

(b) EFFECTIVE DATES.—

(1) IN GENERAL.—Except as otherwise provided in this subsection, the amendments made by this section shall apply to contributions made after December 31, 2025.

(2) MODIFIED INFLATION ADJUSTMENT.—The amendment made by subsection (a)(1) shall apply to taxable years beginning after December 31, 2025.

SEC. 70116. EXTENSION AND ENHANCEMENT OF SAVERS CREDIT ALLOWED FOR ABLE CONTRIBUTIONS.

(a) EXTENSION.—

(1) IN GENERAL.—Section 25B(d)(1) is amended to read as follows:

"(1) IN GENERAL.—The term 'qualified retirement savings contributions' means, with respect to any taxable year, the sum of—

"(A) the amount of contributions made by the eligible individual during such taxable year to the ABLE account (within the meaning of section 529A) of which such individual is the designated beneficiary, and

"(B) in the case of any taxable year beginning before January 1, 2027—

"(i) the amount of the qualified retirement contributions (as defined in section 219(e)) made by the eligible individual,

"(ii) the amount of—

"(I) any elective deferrals (as defined in section 402(g)(3)) of such individual, and

"(II) any elective deferral of compensation by such individual under an eligible deferred compensation plan (as defined in section 457(b)) of an eligible employer described in section 457(e)(1)(A), and

"(iii) the amount of voluntary employee contributions by such individual to any qualified retirement plan (as defined in section 4974(c)).".

(2) COORDINATION WITH SECURE 2.0 ACT OF 2022 AMENDMENT.—Paragraph (1) of section 103(e) of the SECURE 2.0 Act of 2022 is repealed, and the Internal Revenue Code of 1986 shall be applied and administered as though such paragraph were never enacted.

(3) EFFECTIVE DATE.—The amendments and repeal made by this subsection shall apply to taxable years ending after December 31, 2025.

(b) INCREASE OF CREDIT AMOUNT.—

(1) IN GENERAL.—Section 25B(a) is amended by striking "$2,000" and inserting "$2,100".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to taxable years beginning after December 31, 2026.

SEC. 70117. EXTENSION OF ROLLOVERS FROM QUALIFIED TUITION PROGRAMS TO ABLE ACCOUNTS PERMITTED.

(a) IN GENERAL.—Section 529(c)(3)(C)(i)(III) is amended by striking "before January 1, 2026,".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70118. EXTENSION OF TREATMENT OF CERTAIN INDIVIDUALS PERFORMING SERVICES IN THE SINAI PENINSULA AND ENHANCEMENT TO INCLUDE ADDITIONAL AREAS.

(a) TREATMENT MADE PERMANENT.—Section 11026(a) of Public Law 115–97 is amended by striking ", with respect to the applicable period".

(b) KENYA, MALI, BURKINA FASO, AND CHAD INCLUDED AS HAZARDOUS DUTY AREAS.—Section 11026(b) of Public Law 115–97 is amended to read as follows:

"(b) QUALIFIED HAZARDOUS DUTY AREA.—For purposes of this section, the term 'qualified hazardous duty area' means each of the following locations, but only during the period for which any member of the Armed Forces of the United States is entitled to special pay under section 310 of title 37, United States Code (relating to special pay; duty subject to hostile fire or imminent danger), for services performed in such location:

"(1) the Sinai Peninsula of Egypt.

"(2) Kenya.

"(3) Mali.

"(4) Burkina Faso.

"(5) Chad.".

(c) CONFORMING AMENDMENT.—Section 11026 of Public Law 115–97 is amended by striking subsections (c) and (d).

(d) EFFECTIVE DATE.—The amendments made by this section shall take effect on January 1, 2026.

SEC. 70119. EXTENSION AND MODIFICATION OF EXCLUSION FROM GROSS INCOME OF STUDENT LOANS DISCHARGED ON ACCOUNT OF DEATH OR DISABILITY.

(a) IN GENERAL.—Section 108(f)(5) is amended to read as follows:

"(5) DISCHARGES ON ACCOUNT OF DEATH OR DISABILITY.—

"(A) IN GENERAL.—In the case of an individual, gross income does not include any amount which (but for this subsection) would be includible in gross income for such taxable year by reason of the discharge (in whole or in part) of any loan described in subparagraph (B), if such discharge was—

"(i) pursuant to subsection (a) or (d) of section 437 of the Higher Education Act of 1965 or the parallel benefit under part D of title IV of such Act (relating to the repayment of loan liability),

"(ii) pursuant to section 464(c)(1)(F) of such Act, or

"(iii) otherwise discharged on account of death or total and permanent disability of the student.

"(B) LOANS DISCHARGED.—A loan is described in this subparagraph if such loan is—

"(i) a student loan (as defined in paragraph (2)), or

"(ii) a private education loan (as defined in section 140(a) of the Consumer Credit Protection Act (15 U.S.C. 1650(a)).

"(C) SOCIAL SECURITY NUMBER REQUIREMENT.—

"(i) IN GENERAL.—Subparagraph (A) shall not apply with respect to any discharge during any taxable year unless the taxpayer includes the taxpayer's social security number on the return of tax for such taxable year.

"(ii) SOCIAL SECURITY NUMBER.—For purposes of this subparagraph, the term 'social security number' has the meaning given such term in section 24(h)(7).".

(b) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2), as amended by this Act, is further amended by striking "and" at the end of subparagraph (V), by striking the period at the end of subparagraph (W) and inserting ", and", and by inserting after subparagraph (W) the following new subparagraph:

"(X) an omission of a correct social security number required under section 108(f)(5)(C) (relating to discharges on account of death or disability).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to discharges after December 31, 2025.

SEC. 70120. LIMITATION ON INDIVIDUAL DEDUCTIONS FOR CERTAIN STATE AND LOCAL TAXES, ETC.

(a) IN GENERAL.—Section 164(b)(6) is amended—

(1) by striking "and before January 1, 2026", and

(2) by striking "$10,000 ($5,000 in the case of a married individual filing a separate return)" and inserting "the applicable limitation amount (half the applicable limitation amount in the case of a married individual filing a separate return)".

(b) APPLICABLE LIMITATION AMOUNT.—Section 164(b) is amended by adding at the end the following new paragraph:

"(7) APPLICABLE LIMITATION AMOUNT.—

"(A) IN GENERAL.—For purposes of paragraph (6), the term 'applicable limitation amount' means—

"(i) in the case of any taxable year beginning in calendar year 2025, $40,000,

"(ii) in the case of any taxable year beginning in calendar year 2026, $40,400,

"(iii) in the case of any taxable year beginning after calendar year 2026 and before 2030, 101 percent of the dollar amount in effect under this subparagraph for taxable years beginning in the preceding calendar year, and

"(iv) in the case of any taxable year beginning after calendar year 2029, $10,000.

"(B) PHASEDOWN BASED ON MODIFIED ADJUSTED GROSS INCOME.—

"(i) IN GENERAL.—Except as provided in clause (iii), in the case of any taxable year beginning before January 1, 2030, the applicable limitation amount shall be reduced by 30 percent of the excess (if any) of the taxpayer's modified adjusted gross income over the threshold amount (half the threshold amount in the case of a married individual filing a separate return).

"(ii) THRESHOLD AMOUNT.—For purposes of this subparagraph, the term 'threshold amount' means—

"(I) in the case of any taxable year beginning in calendar year 2025, $500,000,

"(II) in the case of any taxable year beginning in calendar year 2026, $505,000, and

"(III) in the case of any taxable year beginning after calendar year 2026, 101 percent of the dollar amount in effect under this subparagraph for taxable years beginning in the preceding calendar year.

"(iii) LIMITATION ON REDUCTION.—The reduction under clause (i) shall not result in the applicable limitation amount being less than $10,000.

"(iv) MODIFIED ADJUSTED GROSS INCOME.—For purposes of this paragraph, the term 'modified adjusted gross income' means adjusted gross income increased by any amount excluded from gross income under section 911, 931, or 933.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

CHAPTER 2—DELIVERING ON PRESIDENTIAL PRIORITIES TO PROVIDE NEW MIDDLE-CLASS TAX RELIEF

SEC. 70201. NO TAX ON TIPS.

(a) DEDUCTION ALLOWED.—Part VII of subchapter B of chapter 1 is amended by redesignating section 224 as section 225 and by inserting after section 223 the following new section:

"SEC. 224. QUALIFIED TIPS.

"(a) IN GENERAL.—There shall be allowed as a deduction an amount equal to the qualified tips received during the taxable year that are included on statements furnished to the individual pursuant to section 6041(d)(3), 6041A(e)(3), 6050W(f)(2), or 6051(a)(18), or reported by the taxpayer on Form 4137 (or successor).

"(b) LIMITATION.—

"(1) IN GENERAL.—The amount allowed as a deduction under this section for any taxable year shall not exceed $25,000.

"(2) LIMITATION BASED ON ADJUSTED GROSS INCOME.—

"(A) IN GENERAL.—The amount allowable as a deduction under subsection (a) (after application of paragraph (1)) shall be reduced (but not below zero) by $100 for each $1,000 by which the taxpayer's modified adjusted gross income exceeds $150,000 ($300,000 in the case of a joint return).

"(B) MODIFIED ADJUSTED GROSS INCOME.—For purposes of this paragraph, the term 'modified adjusted gross income' means the adjusted gross income of the taxpayer for the taxable year increased by any amount excluded from gross income under section 911, 931, or 933.

"(c) TIPS RECEIVED IN COURSE OF TRADE OR BUSINESS.—In the case of qualified tips received by an individual during any taxable year in the course of a trade or business (other than the trade or business of performing services as an employee) of such individual, such qualified tips shall be taken into account under subsection (a) only to the extent that the gross income for the taxpayer from such trade or business for such taxable year (including such qualified tips) exceeds the sum of the deductions (other than the deduction allowed under this section) allocable to the trade or business in which such qualified tips are received by the individual for such taxable year.

"(d) QUALIFIED TIPS.—For purposes of this section—

"(1) IN GENERAL.—The term 'qualified tips' means cash tips received by an individual in an occupation which customarily and regularly received tips on or before December 31, 2024, as provided by the Secretary.

"(2) EXCLUSIONS.—Such term shall not include any amount received by an individual unless—

"(A) such amount is paid voluntarily without any consequence in the event of nonpayment, is not the subject of negotiation, and is determined by the payor, "(B) the trade or business in the course of which the individual receives such amount is not a specified service trade or business (as defined in section 199A(d)(2)), and

"(C) such other requirements as may be established by the Secretary in regulations or other guidance are satisfied.

For purposes of subparagraph (B), in the case of an individual receiving tips in the trade or business of performing services as an employee, such individual shall be treated as receiving tips in the course of a trade or business which is a specified service trade or business if the trade or business of the employer is a specified service trade or business.

"(3) CASH TIPS.—For purposes of paragraph (1), the term 'cash tips' includes tips received from customers that are paid in cash or charged and, in the case of an employee, tips received under any tip-sharing arrangement.

"(e) SOCIAL SECURITY NUMBER REQUIRED.—

"(1) IN GENERAL.—No deduction shall be allowed under this section unless the taxpayer includes on the return of tax for the taxable year such individual's social security number.

"(2) SOCIAL SECURITY NUMBER DEFINED.—For purposes of paragraph (1), the term 'social security number' shall have the meaning given such term in section 24(h)(7).

"(f) MARRIED INDIVIDUALS.—If the taxpayer is a married individual (within the meaning of section 7703), this section shall apply only if the taxpayer and the taxpayer's spouse file a joint return for the taxable year.

"(g) REGULATIONS.—The Secretary shall prescribe such regulations or other guidance as may be necessary to prevent reclassification of income as qualified tips, including regulations or other guidance to prevent abuse of the deduction allowed by this section.

"(h) TERMINATION.—No deduction shall be allowed under this section for any taxable year beginning after December 31, 2028.".

(b) DEDUCTION ALLOWED TO NON-ITEMIZERS.—Section 63(b) is amended by striking "and" at the end of paragraph (3), by striking the period at the end of paragraph (4) and inserting ", and", and by adding at the end the following new paragraph:

"(5) the deduction provided in section 224.".

(c) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2), as amended by the preceding provisions of this Act, is amended by striking "and" at the end of subparagraph (W), by striking the period at the end of subparagraph (X) and inserting ", and", and by inserting after subparagraph (X) the following new subparagraph:

"(Y) an omission of a correct social security number required under section 224(e) (relating to deduction for qualified tips).".

(d) EXCLUSION FROM QUALIFIED BUSINESS INCOME.—Section 199A(c)(4) is amended by striking "and" at the end of subparagraph (B), by striking the period at the end of subparagraph (C) and inserting ", and", and by adding at the end the following new subparagraph:

"(D) any amount with respect to which a deduction is allowable to the taxpayer under section 224(a) for the taxable year.".

(e) EXTENSION OF TIP CREDIT TO BEAUTY SERVICE BUSINESS.—

(1) IN GENERAL.—Section 45B(b)(2) is amended to read as follows:

"(2) APPLICATION ONLY TO CERTAIN LINES OF BUSINESS.— In applying paragraph (1) there shall be taken into account only tips received from customers or clients in connection with the following services:

"(A) The providing, delivering, or serving of food or beverages for consumption, if the tipping of employees delivering or serving food or beverages by customers is customary.

"(B) The providing of any of the following services to a customer or client if the tipping of employees providing such services is customary:

"(i) Barbering and hair care.

"(ii) Nail care.

"(iii) Esthetics.

"(iv) Body and spa treatments.".

(2) CREDIT DETERMINED WITH RESPECT TO MINIMUM WAGE IN EFFECT.—Section 45B(b)(1)(B) is amended—

(A) by striking "as in effect on January 1, 2007, and", and

(B) by inserting ", and in the case of food or beverage establishments, as in effect on January 1, 2007" after "without regard to section 3(m) of such Act".

(f) REPORTING REQUIREMENTS.—

(1) RETURNS FOR PAYMENTS MADE IN THE COURSE OF A TRADE OR BUSINESS.—

(A) STATEMENT FURNISHED TO SECRETARY.—Section 6041(a) is amended by inserting "(including a separate accounting of any such amounts reasonably designated as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips)" after "such gains, profits, and income".

(B) STATEMENT FURNISHED TO PAYEE.—Section 6041(d) is amended by striking "and" at the end of paragraph (1), by striking the period at the end of paragraph (2) and inserting ", and", and by inserting after paragraph (2) the following new paragraph:

"(3) in the case of compensation to non-employees, the portion of payments that have been reasonably designated as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips.".

(2) RETURNS FOR PAYMENTS MADE FOR SERVICES AND DIRECT SALES.—

(A) STATEMENT FURNISHED TO SECRETARY.—Section 6041A(a) is amended by inserting "(including a separate accounting of any such amounts reasonably designated as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips)" after "amount of such payments".

(B) STATEMENT FURNISHED TO PAYEE.—Section 6041A(e) is amended by striking "and" at the end of paragraph (1), by striking the period at the end of paragraph (2) and inserting ", and", and by inserting after paragraph (2) the following new paragraph:

"(3) in the case of subsection (a), the portion of payments that have been reasonably designated as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips.".

(3) RETURNS RELATING TO THIRD PARTY SETTLEMENT ORGANIZATIONS.—

(A) STATEMENT FURNISHED TO SECRETARY.—Section 6050W(a) is amended by striking "and" at the end of paragraph (1), by striking the period at the end of paragraph (2) and inserting "and", and by adding at the end the following new paragraph:

"(3) in the case of a third party settlement organization, the portion of reportable payment transactions that have been reasonably designated by payors as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips.".

(B) STATEMENT FURNISHED TO PAYEE.—Section 6050W(f)(2) is amended by inserting "(including a separate accounting of any such amounts that have been reasonably designated by payors as cash tips and the occupation described in section 224(d)(1) of the person receiving such tips)" after "reportable payment transactions".

(4) RETURNS RELATED TO WAGES.—Section 6051(a) is amended by striking "and" at the end of paragraph (16), by striking the period at the end of paragraph (17) and inserting ", and", and by inserting after paragraph (17) the following new paragraph:

"(18) the total amount of cash tips reported by the employee under section 6053(a) and the occupation described in section 224(d)(1) such person.".

(g) CLERICAL AMENDMENT.—The table of sections for part VII of subchapter B of chapter 1 is amended by redesignating the item relating to section 224 as relating to section 225 and by inserting after the item relating to section 223 the following new item:

"Sec. 224. Qualified tips.".

(h) PUBLISHED LIST OF OCCUPATIONS TRADITIONALLY RECEIVING TIPS.—Not later than 90 days after the date of the enactment of this Act, the Secretary of the Treasury (or the Secretary's delegate) shall publish a list of occupations which customarily and regularly received tips on or before December 31, 2024, for purposes of section 224(d)(1) of the Internal Revenue Code of 1986 (as added by subsection (a)).

(i) WITHHOLDING.—The Secretary of the Treasury (or the Secretary's delegate) shall modify the procedures prescribed under section 3402(a) of the Internal Revenue Code of 1986 for taxable years beginning after December 31, 2025, to take into account the deduction allowed under section 224 of such Code (as added by this Act).

(j) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

(k) TRANSITION RULE.—In the case of any cash tips required to be reported for periods before January 1, 2026, persons required to file returns or statements under section 6041(a), 6041(d)(3), 6041A(a), 6041A(e)(3), 6050W(a), or 6050W(f)(2) of the Internal Revenue Code of 1986 (as amended by this section) may approximate a separate accounting of amounts designated as cash tips by any reasonable method specified by the Secretary.

SEC. 70202. NO TAX ON OVERTIME.

(a) DEDUCTION ALLOWED.—Part VII of subchapter B of chapter 1, as amended by the preceding provisions of this Act, is amended by redesignating section 225 as section 226 and by inserting after section 224 the following new section:

"SEC. 225. QUALIFIED OVERTIME COMPENSATION.

"(a) IN GENERAL.—There shall be allowed as a deduction an amount equal to the qualified overtime compensation received during the taxable year and included on statements furnished to the individual pursuant to section 6041(d)(4) or 6051(a)(19).

"(b) LIMITATION.—

"(1) IN GENERAL.—The amount allowed as a deduction under this section for any taxable year shall not exceed $12,500 ($25,000 in the case of a joint return).

"(2) LIMITATION BASED ON ADJUSTED GROSS INCOME.—

"(A) IN GENERAL.—The amount allowable as a deduction under subsection (a) (after application of paragraph (1)) shall be reduced (but not below zero) by $100 for each $1,000 by which the taxpayer's modified adjusted gross income exceeds $150,000 ($300,000 in the case of a joint return).

"(B) MODIFIED ADJUSTED GROSS INCOME.—For purposes of this paragraph, the term 'modified adjusted gross income' means the adjusted gross income of the taxpayer for the taxable year increased by any amount excluded from gross income under section 911, 931, or 933.

"(c) QUALIFIED OVERTIME COMPENSATION.—

"(1) IN GENERAL.—For purposes of this section, the term 'qualified overtime compensation' means overtime compensation paid to an individual required under section 7 of the Fair Labor Standards Act of 1938 that is in excess of the regular rate (as used in such section) at which such individual is employed.

"(2) EXCLUSIONS.—Such term shall not include any qualified tip (as defined in section 224(d)).

"(d) SOCIAL SECURITY NUMBER REQUIRED.—

"(1) IN GENERAL.—No deduction shall be allowed under this section unless the taxpayer includes on the return of tax for the taxable year such individual's social security number.

"(2) SOCIAL SECURITY NUMBER DEFINED.—For purposes of paragraph (1), the term 'social security number' shall have the meaning given such term in section 24(h)(7).

"(e) MARRIED INDIVIDUALS.—If the taxpayer is a married individual (within the meaning of section 7703), this section shall apply only if the taxpayer and the taxpayer's spouse file a joint return for the taxable year.

"(f) REGULATIONS.—The Secretary shall issue such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this section, including regulations or other guidance to prevent abuse of the deduction allowed by this section.

"(g) TERMINATION.—No deduction shall be allowed under this section for any taxable year beginning after December 31, 2028.".

(b) DEDUCTION ALLOWED TO NON-ITEMIZERS.—Section 63(b), as amended by the preceding provisions of this Act, is amended by striking "and" at the end of paragraph (4), by striking the period at the end of paragraph (5) and inserting ", and", and by adding at the end the following new paragraph:

"(6) the deduction provided in section 225.".

(c) REPORTING.—

(1) REQUIREMENT TO INCLUDE OVERTIME COMPENSATION ON W-2.—Section 6051(a), as amended by the preceding provision of this Act, is amended by striking "and" at the end of paragraph (17), by striking the period at the end of paragraph (18) and inserting ", and", and by inserting after paragraph (18) the following new paragraph:

"(19) the total amount of qualified overtime compensation (as defined in section 225(c)).".

(2) PAYMENTS TO PERSONS NOT TREATED AS EMPLOYEES UNDER TAX LAWS.—

(A) STATEMENT FURNISHED TO SECRETARY.—Section 6041(a), as amended by section 70201(e)(1)(A), is amended by inserting "and a separate accounting of any amount of qualified overtime compensation (as defined in section 225(c))" after "occupation of the person receiving such tips".

(B) STATEMENT FURNISHED TO PAYEE.—Section 6041(d), as amended by section 70201(e)(1)(B), is amended by striking "and" at the end of paragraph (2), by striking the period at the end of paragraph (3) and inserting ", and", and by inserting after paragraph (3) the following new paragraph:

"(4) the portion of payments that are qualified overtime compensation (as defined in section 225(c)).".

(d) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2), as amended by the preceding provisions of this Act, is amended by striking "and" at the end of subparagraph (X), by striking the period at the end of subparagraph (Y) and inserting ", and", and by inserting after subparagraph (Y) the following new subparagraph:

"(Z) an omission of a correct social security number required under section 225(d) (relating to deduction for qualified overtime).".

(e) CLERICAL AMENDMENT.—The table of sections for part VII of subchapter B of chapter 1, as amended by the preceding provisions of this Act, is amended by redesignating the item relating to section 225 as an item relating to section 226 and by inserting after the item relating to section 224 the following new item:

"Sec. 225. Qualified overtime compensation.".

(f) WITHHOLDING.—The Secretary of the Treasury (or the Secretary's delegate) shall modify the procedures prescribed under section 3402(a) of the Internal Revenue Code of 1986 for taxable years beginning after December 31, 2025, to take into account the deduction allowed under section 225 of such Code (as added by this Act).

(g) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

(h) TRANSITION RULE.—In the case of qualified overtime compensation required to be reported for periods before January 1, 2026, persons required to file returns or statements under section 6051(a)(19), 6041(a), or 6041(d)(4) of the Internal Revenue Code of 1986 (as amended by this section) may approximate a separate accounting of amounts designated as qualified overtime compensation by any reasonable method specified by the Secretary.

SEC. 70203. NO TAX ON CAR LOAN INTEREST.

(a) IN GENERAL.—Section 163(h) is amended by redesignating paragraph (4) as paragraph (5) and by inserting after paragraph (3) the following new paragraph:

"(4) SPECIAL RULES FOR TAXABLE YEARS 2025 THROUGH 2028 RELATING TO QUALIFIED PASSENGER VEHICLE LOAN INTEREST.—

"(A) IN GENERAL.—In the case of taxable years beginning after December 31, 2024, and before January 1, 2029, for purposes of this subsection the term 'personal interest' shall not include qualified passenger vehicle loan interest.

"(B) QUALIFIED PASSENGER VEHICLE LOAN INTEREST DEFINED.—

"(i) IN GENERAL.—For purposes of this paragraph, the term 'qualified passenger vehicle loan interest' means any interest which is paid or accrued during the taxable year on indebtedness incurred by the taxpayer after December 31, 2024, for the purchase of, and that is secured by a first lien on, an applicable passenger vehicle for personal use.

"(ii) EXCEPTIONS.—Such term shall not include any amount paid or incurred on any of the following:

"(I) A loan to finance fleet sales.

"(II) A loan incurred for the purchase of a commercial vehicle that is not used for personal purposes.

"(III) Any lease financing.

"(IV) A loan to finance the purchase of a vehicle with a salvage title.

"(V) A loan to finance the purchase of a vehicle intended to be used for scrap or parts.

"(iii) VIN REQUIREMENT.—Interest shall not be treated as qualified passenger vehicle loan interest under this paragraph unless the taxpayer includes the vehicle identification number of the applicable passenger vehicle described in clause (i) on the return of tax for the taxable year.

"(C) LIMITATIONS.—

"(i) DOLLAR LIMIT.—The amount of interest taken into account by a taxpayer under subparagraph (B) for any taxable year shall not exceed $10,000.

"(ii) LIMITATION BASED ON MODIFIED ADJUSTED GROSS INCOME.—

"(I) IN GENERAL.—The amount which is otherwise allowable as a deduction under subsection (a) as qualified passenger vehicle loan interest (determined without regard to this clause and after the application of clause (i)) shall be reduced (but not below zero) by $200 for each $1,000 (or portion thereof) by which the modified adjusted gross income of the taxpayer for the taxable year exceeds $100,000 ($200,000 in the case of a joint return).

"(II) MODIFIED ADJUSTED GROSS INCOME.—For purposes of this clause, the term 'modified adjusted gross income' means the adjusted gross income of the taxpayer for the taxable year increased by any amount excluded from gross income under section 911, 931, or 933.

"(D) APPLICABLE PASSENGER VEHICLE.—The term 'applicable passenger vehicle' means any vehicle—

"(i) the original use of which commences with the taxpayer,

"(ii) which is manufactured primarily for use on public streets, roads, and highways (not including a vehicle operated exclusively on a rail or rails),

"(iii) which has at least 2 wheels,

"(iv) which is a car, minivan, van, sport utility vehicle, pickup truck, or motorcycle,

"(v) which is treated as a motor vehicle for purposes of title II of the Clean Air Act, and

"(vi) which has a gross vehicle weight rating of less than 14,000 pounds.

Such term shall not include any vehicle the final assembly of which did not occur within the United States.

"(E) OTHER DEFINITIONS AND SPECIAL RULES.—For purposes of this paragraph—

"(i) FINAL ASSEMBLY.—For purposes of subparagraph (D), the term 'final assembly' means the process by which a manufacturer produces a vehicle at, or through the use of, a plant, factory, or other place from which the vehicle is delivered to a dealer with all component parts necessary for the mechanical operation of the vehicle included with the vehicle, whether or not the component parts are permanently installed in or on the vehicle.

"(ii) TREATMENT OF REFINANCING.—Indebtedness described in subparagraph (B) shall include indebtedness that results from refinancing any indebtedness described in such subparagraph, and that is secured by a first lien on the applicable passenger vehicle with respect to which the refinanced indebtedness was incurred, but only to the extent the amount of such resulting indebtedness does not exceed the amount of such refinanced indebtedness.

"(iii) RELATED PARTIES.—Indebtedness described in subparagraph (B) shall not include any indebtedness owed to a person who is related (within the meaning of section 267(b) or 707(b)(1)) to the taxpayer.".

(b) DEDUCTION ALLOWED TO NON-ITEMIZERS.—Section 63(b), as amended by the preceding provisions of this Act, is amended by striking "and" at the end of paragraph (5), by striking the period at the end of paragraph (6) and inserting "and", and by adding at the end the following new paragraph:

"(7) so much of the deduction allowed by section 163(a) as is attributable to the exception under section 163(h)(4)(A).".

(c) REPORTING.—

(1) IN GENERAL.—Subpart B of part III of subchapter A of chapter 61 is amended by adding at the end the following new section:

"SEC. 6050AA. RETURNS RELATING TO APPLICABLE PASSENGER VEHICLE LOAN INTEREST RECEIVED IN TRADE OR BUSINESS FROM INDIVIDUALS.

"(a) IN GENERAL.—Any person—

"(1) who is engaged in a trade or business, and

"(2) who, in the course of such trade or business, receives from any individual interest aggregating $600 or more for any calendar year on a specified passenger vehicle loan,

shall make the return described in subsection (b) with respect to each individual from whom such interest was received at such time as the Secretary may provide.

"(b) FORM AND MANNER OF RETURNS.—A return is described in this subsection if such return—

"(1) is in such form as the Secretary may prescribe, and

"(2) contains—

"(A) the name and address of the individual from whom the interest described in subsection (a)(2) was received,

"(B) the amount of such interest received for the calendar year,

"(C) the amount of outstanding principal on the specified passenger vehicle loan as of the beginning of such calendar year,

"(D) the date of the origination of such loan,

"(E) the year, make, model, and vehicle identification number of the applicable passenger vehicle which secures such loan (or such other description of such vehicle as the Secretary may prescribe), and

"(F) such other information as the Secretary may prescribe.

"(c) STATEMENTS TO BE FURNISHED TO INDIVIDUALS WITH RESPECT TO WHOM INFORMATION IS REQUIRED.—Every person required to make a return under subsection (a) shall furnish to each individual whose name is required to be set forth in such return a written statement showing—

"(1) the name, address, and phone number of the information contact of the person required to make such return, and

"(2) the information described in subparagraphs (B), (C), (D), and (E) of subsection (b)(2) with respect to such individual (and such information as is described in subsection (b)(2)(F) with respect to such individual as the Secretary may provide for purposes of this subsection).

The written statement required under the preceding sentence shall be furnished on or before January 31 of the year following the calendar year for which the return under subsection (a) was required to be made.

"(d) DEFINITIONS.—For purposes of this section—

"(1) IN GENERAL.—Terms used in this section which are also used in paragraph (4) of section 163(h) shall have the same meaning as when used in such paragraph.

"(2) SPECIFIED PASSENGER VEHICLE LOAN.—The term 'specified passenger vehicle loan' means the indebtedness described in section 163(h)(4)(B) with respect to any applicable passenger vehicle.

"(e) REGULATIONS.—The Secretary shall issue such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this section, including regulations or other guidance to prevent the duplicate reporting of information under this section.

"(f) APPLICABILITY.—No return shall be required under this section for any period to which section 163(h)(4) does not apply.".

(2) PENALTIES.—Section 6724(d) is amended—

(A) in paragraph (1)(B), by striking "or" at the end of clause (xxvii), by striking "and" at the end of clause (xxviii) and inserting "or", and by adding at the end the following new clause:

"(xxix) section 6050AA(a) (relating to returns relating to applicable passenger vehicle loan interest received in trade or business from individuals),", and

(B) in paragraph (2), by striking "or" at the end of subparagraph (KK), by striking the period at the end of subparagraph (LL) and inserting ", or", and by inserting after subparagraph (LL) the following new subparagraph:

"(MM) section 6050AA(c) (relating to statements relating to applicable passenger vehicle loan interest received in trade or business from individuals).".

(d) CONFORMING AMENDMENTS.—

(1) Section 56(e)(1)(B) is amended by striking "section 163(h)(4)" and inserting "section 163(h)(5)".

(2) The table of sections for subpart B of part III of subchapter A of chapter 61 is amended by adding at the end the following new item:

(e) EFFECTIVE DATE.—The amendments made by this section shall apply to indebtedness incurred after December 31, 2024.

SEC. 70204. TRUMP ACCOUNTS AND CONTRIBUTION PILOT PROGRAM.

(a) TRUMP ACCOUNTS.—

(1) IN GENERAL.—Subchapter F of chapter 1 is amended by adding at the end the following new part:

"PART IX—TRUMP ACCOUNTS

"SEC. 530A. TRUMP ACCOUNTS.

"(a) GENERAL RULE.—Except as provided in this section or under regulations or guidance established by the Secretary, a Trump account shall be treated for purposes of this title in the same manner as an individual retirement account under section 408(a).

"(b) TRUMP ACCOUNT.—For purposes of this section—

"(1) IN GENERAL.—The term 'Trump account' means an individual retirement account (as defined in section 408(a)) which is not designated as a Roth IRA and which meets the following requirements:

"(A) The account—

"(i) is created or organized by the Secretary for the exclusive benefit of an eligible individual or such eligible individual's beneficiaries, or

"(ii) is—

"(I) created or organized in the United States for the exclusive benefit of an individual who has not attained the age of 18 before the end of the calendar year, or such individual's beneficiaries, and

"(II) funded by a qualified rollover contribution.

"(B) The account is designated (in such manner as the Secretary shall prescribe) at the time of the establishment of the account as a Trump account.

"(C) The written governing instrument creating the account meets the following requirements:

"(i) No contribution will be accepted—

"(I) before the date that is 12 months after the date of the enactment of this section, or

"(II) in the case of a contribution made in any calendar year before the calendar year in which the account beneficiary attains age 18, if such contribution would result in aggregate contributions (other than exempt contributions) for such calendar year in excess of the contribution limit specified in subsection (c)(2)(A).

"(ii) Except as provided in subsection (d), no distribution will be allowed before the first day of the calendar year in which the account beneficiary attains age 18.

"(iii) No part of the account funds will be invested in any asset other than an eligible investment during any period before the first day of the calendar year in which the account beneficiary attains age 18.

"(2) ELIGIBLE INDIVIDUAL.—The term 'eligible individual' means any individual—

"(A) who has not attained the age of 18 before the close of the calendar year in which the election under subparagraph (C) is made,

"(B) for whom a social security number (within the meaning of section 24(h)(7)) has been issued before the date on which an election under subsection (C) is made, and

"(C) for whom—

"(i) an election is made under this subparagraph by the Secretary if the Secretary determines (based on information available to the Secretary from tax returns or otherwise) that such individual meets the requirements of subparagraphs (A) and (B) and no prior election has been made for such individual under clause (ii), or

"(ii) an election is made under this subparagraph by a person other than the Secretary (at such time and in such manner as the Secretary may prescribe) for the establishment of a Trump account if no prior election has been made for such individual under clause (i).

"(3) ELIGIBLE INVESTMENT.—

"(A) IN GENERAL.—The term 'eligible investment' means any mutual fund or exchange traded fund which—

"(i) tracks the returns of a qualified index,

"(ii) does not use leverage,

"(iii) does not have annual fees and expenses of more than 0.1 percent of the balance of the investment in the fund, and

"(iv) meets such other criteria as the Secretary determines appropriate for purposes of this section.

"(B) QUALIFIED INDEX.—The term 'qualified index' means—

"(i) the Standard and Poor's 500 stock market index, or

"(ii) any other index—

"(I) which is comprised of equity investments in primarily United States companies, and

"(II) for which regulated futures contracts (as defined in section 1256(g)(1)) are traded on a qualified board or exchange (as defined in section 1256(g)(7)).

Such term shall not include any industry or sector-specific index, but may include an index based on market capitalization.

"(4) ACCOUNT BENEFICIARY.—The term 'account beneficiary' means the individual on whose behalf the Trump account was established.

"(c) TREATMENT OF CONTRIBUTIONS.—

"(1) NO DEDUCTION ALLOWED.—No deduction shall be allowed under section 219 for any contribution which is made before the first day of the calendar year in which the account beneficiary attains age 18.

"(2) CONTRIBUTION LIMIT.—In the case of any contribution made before the calendar year in which the account beneficiary attains age 18—

"(A) IN GENERAL.—The aggregate amount of contributions (other than exempt contributions) for such calendar year shall not exceed $5,000.

"(B) EXEMPT CONTRIBUTION.—For purposes of this paragraph, the term 'exempt contribution' means—

"(i) a qualified rollover contribution,

"(ii) any qualified general contribution, or

"(iii) any contribution provided under section 6434.

"(C) COST-OF-LIVING ADJUSTMENT.—

"(i) IN GENERAL.—In the case of any taxable year after 2027, the $5,000 amount under subparagraph (A) shall be increased by an amount equal to—

"(I) such dollar amount, multiplied by

"(II) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2026' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

"(ii) ROUNDING.—If any increase under this subparagraph is not a multiple of $100, such amount shall be rounded to the next lowest multiple of $100.

"(3) TIMING OF CONTRIBUTIONS.—Section 219(f)(3) shall not apply to any contribution made to a Trump account for any taxable year ending before the calendar year in which the account beneficiary attains age 18.

"(d) DISTRIBUTIONS.—

"(1) IN GENERAL.—Except as otherwise provided in this subsection, no distribution shall be allowed before the first day of the calendar year in which the account beneficiary attains age 18.

"(2) TAX TREATMENT OF ALLOWABLE DISTRIBUTIONS.—For purposes of applying section 72 to any amount distributed from a Trump account, the investment in the contract shall not include—

"(A) any qualified general contribution,

"(B) any contribution provided under section 6434, and

"(C) the amount of any contribution which is excluded from gross income under section 128.

"(3) QUALIFIED ROLLOVER CONTRIBUTIONS.—Paragraph (1) shall not apply to any distribution which is a qualified rollover contribution and the amount of such distribution shall not be included in the gross income of the beneficiary.

"(4) QUALIFIED ABLE ROLLOVER CONTRIBUTIONS.—

"(A) IN GENERAL.—Paragraph (1) shall not apply to any distribution which is a qualified ABLE rollover contribution and the amount of such distribution shall not be included in the gross income of the beneficiary.

"(B) QUALIFIED ABLE ROLLOVER CONTRIBUTION.—For purposes of this section, the term 'qualified ABLE rollover contribution' means an amount which is paid during the calendar year in which the account beneficiary attains age 17 in a direct trustee-to-trustee transfer from a Trump account maintained for the benefit of the account beneficiary to an ABLE account (as defined in section 529A(e)(6)) for the benefit of the such account beneficiary, but only if the amount of such payment is equal to the entire balance of the Trump account from which the payment is made.

"(5) DISTRIBUTIONS OF EXCESS CONTRIBUTIONS.—In the case of any contribution which is made before the calendar year in which the account beneficiary attains age 18 and which is in excess of the limitation in effect under subsection (c)(2)(A) for the calendar year—

"(A) paragraph (1) shall not apply to the distribution of such excess,

"(B) the amount of such distribution shall not be included in gross income of the account beneficiary, and

"(C) the tax imposed by this chapter on the distributee for the taxable year in which the distribution is made shall be increased by 100 percent of the amount of net income attributable to such excess (determined without regard to subparagraph (B)).

"(6) TREATMENT OF DEATH OF ACCOUNT BENEFICIARY.—If, by reason of the death of the account beneficiary before the first day of the calendar year in which the account beneficiary attains age 18, any person acquires the account beneficiary's interest in the Trump account—

"(A) paragraph (1) shall not apply,

"(B) such account shall cease to be a Trump account as of the date of death, and

"(C) an amount equal to the fair market value of the assets (reduced by the investment in the contract) in such account on such date shall—

"(i) if such person is not the estate of such beneficiary, be includible in such person's gross income for the taxable year which includes such date, or

"(ii) if such person is the estate of such beneficiary, be includible in such beneficiary's gross income for the last taxable year of such beneficiary.

"(e) QUALIFIED ROLLOVER CONTRIBUTION.—For purposes of this section, the term 'qualified rollover contribution' means an amount which is paid in a direct trustee-to-trustee transfer from a Trump account maintained for the benefit of the account beneficiary to a Trump account maintained for such beneficiary, but only if the amount of such payment is equal to the entire balance of the Trump account from which the payment is made.

"(f) QUALIFIED GENERAL CONTRIBUTION.—For purposes of this section—

"(1) IN GENERAL.—The term 'qualified general contribution' means any contribution which—

"(A) is made by the Secretary pursuant to a general funding contribution,

"(B) is made to the Trump account of an account beneficiary in the qualified class of account beneficiaries specified in the general funding contribution, and

"(C) is in an amount which is equal to the ratio of—

"(i) the amount of such general funding contribution, to

"(ii) the number of account beneficiaries in such qualified class.

"(2) GENERAL FUNDING CONTRIBUTION.—The term 'general funding contribution' means a contribution which—

"(A) is made by—

"(i) an entity described in section 170(c)(1) (other than a possession of the United States or a political subdivision thereof) or an Indian tribal government, or

"(ii) an organization described in section 501(c)(3) and exempt from tax under section 501(a), and

"(B) which specifies a qualified class of account beneficiaries to whom such contribution is to be distributed.

"(3) QUALIFIED CLASS.—

"(A) IN GENERAL.—The term 'qualified class' means any of the following:

"(i) All account beneficiaries who have not attained the age of 18 before the close of the calendar year in which the contribution is made.

"(ii) All account beneficiaries who have not attained the age of 18 before the close of the calendar year in which the contribution is made and who reside in one or more States or other qualified geographic areas specified by the terms of the general funding contribution.

"(iii) All account beneficiaries who have not attained the age of 18 before the close of the calendar year in which the contribution is made and who were born in one or more calendar years specified by the terms of the general funding contribution.

"(B) QUALIFIED GEOGRAPHIC AREA.—The term 'qualified geographic area' means any geographic area in which not less than 5,000 account beneficiaries reside and which is designated by the Secretary as a qualified geographic area under this subparagraph.

"(g) TRUSTEE SELECTION.—In the case of any Trump account created or organized by the Secretary, the Secretary shall take into account the following criteria in selecting the trustee:

"(1) The history of reliability and regulatory compliance of the trustee.

"(2) The customer service experience of the trustee.

"(3) The costs imposed by the trustee on the account or the account beneficiary.

"(h) OTHER SPECIAL RULES AND COORDINATION WITH INDIVIDUAL RETIREMENT ACCOUNT RULES.—

"(1) IN GENERAL.—The rules of subsections (k) and (p) of section 408 shall not apply to a Trump account, and the rules of subsections (d) and (i) of section 408 shall not apply to a Trump account for any taxable year beginning before the calendar year in which the account beneficiary attains age 18.

"(2) CUSTODIAL ACCOUNTS.—In the case of a Trump account, section 408(h) shall be applied by substituting 'a Trump account described in section 530A(b)(1)' for 'an individual retirement account described in subsection (a)'.

"(3) CONTRIBUTIONS.—In the case of any taxable year beginning before the first day of the calendar year in which the account beneficiary attains age 18, a contribution to a Trump account shall not be taken into account in applying any contribution limit to any individual retirement plan other than a Trump account.

"(4) DISTRIBUTIONS.—Section 408(d)(2) shall be applied separately with respect to Trump Accounts and other individual retirement plans.

"(5) EXCESS CONTRIBUTIONS.—For purposes of applying section 4973(b) to a Trump account for any taxable year beginning before the first day of the calendar year in which the account beneficiary attains age 18, the term 'excess contributions' means the sum of—

"(A) the amount by which the amount contributed to the account for the calendar year in which taxable year begins exceeds the amount permitted to be contributed to the account under subsection (c)(2), and

"(B) the amount determined under this paragraph for the preceding taxable year.

For purposes of this paragraph, the excess contributions for a taxable year are reduced by the distributions to which subsection (d)(5) applies that are made during the taxable year or by the date prescribed by law (including extensions of time) for filing the account beneficiary's return for the taxable year.

"(i) REPORTS.—

"(1) IN GENERAL.—The trustee of a Trump account shall make such reports regarding such account to the Secretary and to the beneficiary of the account at such time and in such manner as may be required by the Secretary. Such reports shall include information with respect to—

"(A) contributions (including the amount and source of any contribution in excess of $25 made from a person other than the Secretary, the account beneficiary, or the parent or legal guardian of the account beneficiary),

"(B) distributions (including distributions which are qualified rollover contributions),

"(C) the fair market value of the account,

"(D) the investment in the contract with respect to such account, and

"(E) such other matters as the Secretary may require.

"(2) QUALIFIED ROLLOVER CONTRIBUTIONS.—Not later than 30 days after the date of any qualified rollover contribution, the trustee of the Trump account to which the contribution was made shall make a report to the Secretary. Such report shall include—

"(A) the name, address, and social security number of the account beneficiary,

"(B) the name and address of such trustee,

"(C) the account number,

"(D) the routing number of the trustee, and

"(E) such other information as the Secretary may require.

"(3) PERIOD OF REPORTING.—This subsection shall not apply to any period after the calendar year in which the beneficiary attains age 17.".

(2) QUALIFIED ABLE ROLLOVER CONTRIBUTIONS EXEMPT FROM ABLE CONTRIBUTION LIMITATION.—

(A) IN GENERAL.—Section 529A(b)(2)(B) is amended by inserting "or received in a qualified ABLE rollover contribution described in section 530A(d)(4)(B)" after "except as provided in the case of contributions under subsection (c)(1)(C)".

(B) PROHIBITION ON EXCESS CONTRIBUTIONS.—The second sentence of section 529A(b)(6) is amended by inserting "but do not include any contributions received in a qualified ABLE rollover contribution described in section 530A(d)(4)(B)" before the period at the end.

(C) CONFORMING AMENDMENT.—Section 4973(h)(1) is amended by inserting "or contributions received in a qualified ABLE rollover contribution described in section 530A(d)(4)(B)" after "other than contributions under section 529A(c)(1)(C)".

(3) FAILURE TO PROVIDE REPORTS ON TRUMP ACCOUNTS.— Section 6693(a)(2) is amended by striking "and" at the end of subparagraph (E), by striking the period at the end of subparagraph (F) and inserting ", and", and by inserting after subparagraph (F) the following new subparagraph:

"(G) section 530A(i) (relating to Trump accounts).".

(4) CLERICAL AMENDMENT.—

(A) The table of parts for subchapter F of chapter 1 is amended by adding at the end the following new item:

"PART IX—TRUMP ACCOUNTS".

(b) EMPLOYER CONTRIBUTIONS.—

(1) IN GENERAL.—Part III of subchapter B of chapter 1 is amended by inserting after section 127 the following new section:

"SEC. 128. EMPLOYER CONTRIBUTIONS TO TRUMP ACCOUNTS.

"(a) IN GENERAL.—Gross income of an employee does not include amounts paid by the employer as a contribution to the Trump account of such employee or of any dependent of such employee if the amounts are paid or incurred pursuant to a program which is described in subsection (c).

"(b) LIMITATION.—

"(1) IN GENERAL.—The amount which may be excluded under subsection (a) with respect to any employee shall not exceed $2,500.

"(2) INFLATION ADJUSTMENT.—

"(A) IN GENERAL.—In the case of any taxable year beginning after 2027, the $2,500 amount in paragraph (1) shall be increased by an amount equal to—

"(i) such dollar amount, multiplied by

"(ii) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins by substituting 'calendar year 2026' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

"(B) ROUNDING.—If any increase determined under subparagraph (A) is not a multiple of $100, such increase shall be rounded to the next lowest multiple of $100.

"(c) TRUMP ACCOUNT CONTRIBUTION PROGRAM.—For purposes of this section, a Trump account contribution program is a separate written plan of an employer for the exclusive benefit of his employees to provide contributions to the Trump accounts of such employees or dependents of such employees which meets requirements similar to the requirements of paragraphs (2), (3), (6), (7), and (8) of section 129(d).".

(2) CLERICAL AMENDMENT.—The table of sections for part III of subchapter B of chapter 1 is amended by inserting after the item relating to section 127 the following new item:

"Sec. 128. Employer contributions to Trump accounts.".

(c) CERTAIN CONTRIBUTIONS EXCLUDED FROM GROSS INCOME.—

(1) IN GENERAL.—Part III of subchapter B of chapter 1 is amended by inserting before section 140 the following new section:

"SEC. 139J. CERTAIN CONTRIBUTIONS TO TRUMP ACCOUNTS.

"(a) IN GENERAL.—Gross income of an account beneficiary shall not include any qualified general contribution to a Trump account of the account beneficiary.

"(b) DEFINITIONS.—Any term used in this section which is used in section 530A shall have the meaning given such term under section 530A.".

(2) CLERICAL AMENDMENT.—The table of sections for part III of subchapter B is amended by inserting before the item relating to section 140 the following new item:

"Sec. 139J. Certain contributions to Trump accounts.".

(d) TRUMP ACCOUNTS CONTRIBUTION PILOT PROGRAM.—

(1) IN GENERAL.—Subchapter B of chapter 65 is amended by adding at the end the following new section:

"SEC. 6434. TRUMP ACCOUNTS CONTRIBUTION PILOT PROGRAM.

"(a) IN GENERAL.—In the case of an individual who makes an election under this section with respect to an eligible child of the individual, such eligible child shall be treated as making a payment against the tax imposed by subtitle A (for the taxable year for which the election was made) in an amount equal to $1,000.

"(b) REFUND OF PAYMENT.—The amount treated as a payment under subsection (a) shall be paid by the Secretary to the Trump account with respect to which such eligible child is the account beneficiary.

"(c) ELIGIBLE CHILD.—For purposes of this section, the term 'eligible child' means a qualifying child (as defined in section 152(c))—

"(1) who is born after December 31, 2024, and before January 1, 2029,

"(2) with respect to whom no prior election has been made under this section by such individual or any other individual, and

"(3) who is a United States citizen.

"(d) ELECTION.—An election under this section shall be made at such time and in such manner as the Secretary shall provide.

"(e) SOCIAL SECURITY NUMBER REQUIRED.—

"(1) IN GENERAL.—This section shall not apply to any taxpayer unless such individual includes with the election made under this section the social security number of the eligible child with respect to whom the election is made.

"(2) SOCIAL SECURITY NUMBER DEFINED.—For purposes of paragraph (1), the term 'social security number' shall have the meaning given such term in section 24(h)(7), determined by substituting 'before the date of the election made under section 6434' for 'before the due date of such return' in subparagraph (B) thereof.

"(f) EXCEPTION FROM REDUCTION OR OFFSET.—Any payment made to any individual under this section shall not be—

"(1) subject to reduction or offset pursuant to subsection (c), (d), (e), or (f) of section 6402 or any similar authority permitting offset, or

"(2) reduced or offset by other assessed Federal taxes that would otherwise be subject to levy or collection.

"(g) SPECIAL RULE REGARDING INTEREST.—The period determined under section 6611(a) with respect to any payment under this section shall not begin before January 1, 2028.

"(h) MIRROR CODE POSSESSIONS.—In the case of any possession of the United States with a mirror code tax system (as defined in section 24(k)), this section shall not be treated as part of the income tax laws of the United States for purposes of determining the income tax law of such possession unless such possession elects to have this section be so treated.

"(i) DEFINITIONS.—For purposes of this section, the terms 'Trump account' and 'account beneficiary' have the meaning given such terms in section 530A(b).".

(2) PENALTY FOR NEGLIGENT CLAIM OR FRAUDULENT CLAIM.—Part I of subchapter A of chapter 68 is amended by adding at the end the following new section:

"SEC. 6659. IMPROPER CLAIM FOR TRUMP ACCOUNT CONTRIBUTION PILOT PROGRAM CREDIT.

"(a) IN GENERAL.—In the case of any individual who makes an election under section 6434 with respect to an individual who is not an eligible child of the taxpayer—

"(1) if such election was made due to negligence or disregard of the rules or regulations, there shall be imposed a penalty of $500, or

"(2) if such election was made due to fraud, there shall be imposed a penalty of $1,000.

"(b) DEFINITIONS.—

"(1) ELIGIBLE CHILD.—The term 'eligible child' has the meaning given such term under section 6434.

"(2) NEGLIGENCE; DISREGARD.—The terms 'negligence' and 'disregard' have the same meaning as when such terms are used in section 6662.".

(3) OMISSION OF CORRECT SOCIAL SECURITY NUMBER TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2), as amended by the preceding provisions of this Act, is amended by striking "and" at the end of subparagraph (Y), by striking the period at the end of subparagraph (Z) and inserting ", and", and by inserting after subparagraph (Z) the following new subparagraph:

"(AA) an omission of a correct social security number required under section 6434(e)(1) (relating to the Trump accounts contribution pilot program).".

(4) CONFORMING AMENDMENTS.—

(A) The table of sections for subchapter B of chapter 65 is amended by adding at the end the following new item:

"Sec. 6434. Trump accounts contribution pilot program.".

(B) The table of sections for part I of subchapter A of chapter 68 is amended by inserting after the item relating to section 6658 the following new item:

"Sec. 6659. Improper claim for Trump account contribution pilot program credit.".

(e) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

(f) FUNDING.—In addition to amounts otherwise available, there is appropriated to the Department of the Treasury, out of any money in the Treasury not otherwise appropriated, $410,000,000, to remain available until September 30, 2034, to carry out the amendments made by this section.

CHAPTER 3—ESTABLISHING CERTAINTY AND COMPETITIVENESS FOR AMERICAN JOB CREATORS

Subchapter A—Permanent U.S. Business Tax Reform and Boosting Domestic Investment

SEC. 70301. FULL EXPENSING FOR CERTAIN BUSINESS PROPERTY.

(a) MADE PERMANENT.—

(1) IN GENERAL.—Section 168(k)(2)(A) is amended by adding "and" at the end of clause (i), by striking ", and" at the end of clause (ii) and inserting a period, and by striking clause (iii).

(2) PROPERTY WITH LONGER PRODUCTION PERIODS.—Section 168(k)(2)(B) is amended—

(A) in clause (i), by striking subclauses (II) and (III) and redesignating subclauses (IV), (V), and (VI), as subclauses (II), (III), and (IV), respectively, and

(B) by striking clause (ii) and redesignating clauses (iii) and (iv) as clauses (ii) and (iii), respectively.

(3) SELF-CONSTRUCTED PROPERTY.—Section 168(k)(2)(E) is amended by striking clause (i) and redesignating clauses (ii) and (iii) as clauses (i) and (ii), respectively.

(4) CERTAIN PLANTS.—Section 168(k)(5)(A) is amended by striking "planted before January 1, 2027, or is grafted before such date to a plant that has already been planted," in the matter preceding clause (i) and inserting "planted or grafted".

(5) CONFORMING AMENDMENTS.—

(A) Section 168(k)(2)(A)(ii) is amended by striking "clause (ii) of subparagraph (E)" and inserting "clause (i) of subparagraph (E)".

(B) Section 168(k)(2)(C)(i) is amended by striking "and subclauses (II) and (III) of subparagraph (B)(i)".

(C) Section 168(k)(2)(C)(ii) is amended by striking "subparagraph (B)(iii)" and inserting "subparagraph (B)(ii)".

(D) Section 460(c)(6)(B) is amended by striking "which" and all that follows through the period and inserting "which has a recovery period of 7 years or less.".

(b) 100 PERCENT EXPENSING.—

(1) IN GENERAL.—Section 168(k) is amended—

(A) in paragraph (1)(A), by striking "the applicable percentage" and inserting "100 percent", and

(B) by striking paragraphs (6) and (8).

(2) CERTAIN PLANTS.—Section 168(k)(5)(A)(i) is amended by striking "the applicable percentage" and inserting "100 percent".

(3) TRANSITIONAL ELECTION OF REDUCED PERCENTAGE.—Section 168(k)(10) is amended by striking subparagraph (A), by redesignating subparagraph (B) as subparagraph (C), and by inserting before subparagraph (C) (as so redesignated) the following new subparagraphs:

"(A) IN GENERAL.—In the case of qualified property placed in service by the taxpayer during the first taxable year ending after January 19, 2025, if the taxpayer elects to have this paragraph apply for such taxable year, paragraph (1)(A) shall be applied—

"(i) in the case of property which is not described in clause (ii), by substituting '40 percent' for '100 percent', or

"(ii) in the case of property which is described in subparagraph (B) or (C) of paragraph (2), by substituting '60 percent' for '100 percent'.

"(B) SPECIFIED PLANTS.—In the case of any specified plant planted or grafted by the taxpayer during the first taxable year ending after January 19, 2025, if the taxpayer elects to have this paragraph apply for such taxable year, paragraph (5)(A)(i) shall be applied by substituting '40 percent' for '100 percent'.".

(c) EFFECTIVE DATE.—

(1) IN GENERAL.—Except as otherwise provided in this subsection, the amendments made by this section shall apply to property acquired after January 19, 2025.

(2) SPECIFIED PLANTS.—Except as provided in paragraph (3), in the case of any specified plant (as defined in section 168(k)(5)(B) of the Internal Revenue Code of 1986, as amended by this section), the amendments made by this section shall apply to such plants which are planted or grafted after January 19, 2025.

(3) TRANSITIONAL ELECTION OF REDUCED PERCENTAGE.—The amendment made by subsection (b)(3) shall apply to taxable years ending after January 19, 2025.

(4) ACQUISITION DATE DETERMINATION.—For purposes of paragraph (1), property shall not be treated as acquired after the date on which a written binding contract is entered into for such acquisition.

SEC. 70302. FULL EXPENSING OF DOMESTIC RESEARCH AND EXPERIMENTAL EXPENDITURES.

(a) IN GENERAL.—Part VI of subchapter B of chapter 1 is amended by inserting after section 174 the following new section:

"SEC. 174A. DOMESTIC RESEARCH OR EXPERIMENTAL EXPENDITURES.

"(a) TREATMENT AS EXPENSES.—Notwithstanding section 263, there shall be allowed as a deduction any domestic research or experimental expenditures which are paid or incurred by the taxpayer during the taxable year.

"(b) DOMESTIC RESEARCH OR EXPERIMENTAL EXPENDITURES.—For purposes of this section, the term 'domestic research or experimental expenditures' means research or experimental expenditures paid or incurred by the taxpayer in connection with the taxpayer's trade or business other than such expenditures which are attributable to foreign research (within the meaning of section 41(d)(4)(F)).

"(c) AMORTIZATION OF CERTAIN DOMESTIC RESEARCH OR EXPERIMENTAL EXPENDITURES.—

"(1) IN GENERAL.—At the election of the taxpayer, made in accordance with regulations or other guidance provided by the Secretary, in the case of domestic research or experimental expenditures which would (but for subsection (a)) be chargeable to capital account but not chargeable to property of a character which is subject to the allowance under section 167 (relating to allowance for depreciation, etc.) or section 611 (relating to allowance for depletion), subsection (a) shall not apply and the taxpayer shall—

"(A) charge such expenditures to capital account, and

"(B) be allowed an amortization deduction of such expenditures ratably over such period of not less than 60 months as may be selected by the taxpayer (beginning with the month in which the taxpayer first realizes benefits from such expenditures).

"(2) TIME FOR AND SCOPE OF ELECTION.—The election provided by paragraph (1) may be made for any taxable year, but only if made not later than the time prescribed by law for filing the return for such taxable year (including extensions thereof). The method so elected, and the period selected by the taxpayer, shall be adhered to in computing taxable income for the taxable year for which the election is made and for all subsequent taxable years unless, with the approval of the Secretary, a change to a different method (or to a different period) is authorized with respect to part or all of such expenditures. The election shall not apply to any expenditure paid or incurred during any taxable year before the taxable year for which the taxpayer makes the election.

"(d) SPECIAL RULES.—

"(1) LAND AND OTHER PROPERTY.—This section shall not apply to any expenditure for the acquisition or improvement of land, or for the acquisition or improvement of property to be used in connection with the research or experimentation and of a character which is subject to the allowance under section 167 (relating to allowance for depreciation, etc.) or section 611 (relating to allowance for depletion); but for purposes of this section allowances under section 167, and allowances under section 611, shall be considered as expenditures.

"(2) EXPLORATION EXPENDITURES.—This section shall not apply to any expenditure paid or incurred for the purpose of ascertaining the existence, location, extent, or quality of any deposit of ore or other mineral (including oil and gas).

"(3) SOFTWARE DEVELOPMENT.—For purposes of this section, any amount paid or incurred in connection with the development of any software shall be treated as a research or experimental expenditure.".

(b) COORDINATION WITH CERTAIN OTHER PROVISIONS.—

(1) FOREIGN RESEARCH EXPENSES.—Section 174 is amended—

(A) in subsection (a)—

(i) by striking "a taxpayer's specified research or experimental expenditures" and inserting "a taxpayer's foreign research or experimental expenditures", and

(ii) by striking "over the 5-year period (15-year period in the case of any specified research or experimental expenditures which are attributable to foreign research (within the meaning of section 41(d)(4)(F)))" in paragraph (2)(B) and inserting "over the 15-year period",

(B) in subsection (b)—

(i) by striking "specified research" and inserting "foreign research",

(ii) by inserting "and which are attributable to foreign research (within the meaning of section 41(d)(4)(F))" before the period at the end, and

(iii) by striking "SPECIFIED" in the heading thereof and inserting "FOREIGN", and

(C) in subsection (d)—

(i) by striking "specified research or experimental expenditures" and inserting "foreign research or experimental expenditures", and

(ii) by inserting "or reduction to amount realized" after "no deduction".

(2) RESEARCH CREDIT.—

(A) Section 41(d)(1)(A) is amended to read as follows:

"(A) with respect to which expenditures are treated as domestic research or experimental expenditures under section 174A,".

(B) Section 280C(c)(1) is amended to read as follows:

"(1) IN GENERAL.—The domestic research or experimental expenditures (as defined in section 174A(b)) otherwise taken into account as a deduction or charged to capital account under this chapter shall be reduced by the amount of the credit allowed under section 41(a).".

(3) AMT ADJUSTMENT.—Section 56(b)(2) is amended—

(A) in subparagraph (A)—

(i) by striking "or 174(a)" in the matter preceding clause (i) and inserting ", 174(a), or 174A(a)", and

(ii) by striking "research and experimental expenditures described in section 174(a)" in clause (ii) thereof and inserting "foreign research or experimental expenditures described in section 174(a) and domestic research or experimental expenditures in section 174A(a)", and

(B) in subparagraph (C), by inserting "or 174A(a)" after "174(a)".

(4) OPTIONAL 10-YEAR WRITEOFF.—Section 59(e)(2)(B) is amended by striking "section 174(a) (relating to research and experimental expenditures)" and inserting "section 174A(a) (relating to domestic research or experimental expenditures)".

(5) QUALIFIED SMALL ISSUE BONDS.—Section 144(a)(4)(C)(iv) is amended by striking "174(a)" and inserting "174A(a)".

(6) START-UP EXPENDITURES.—Section 195(c)(1) is amended by striking "or 174" in the last sentence and inserting "174, or 174A".

(7) CAPITAL EXPENDITURES.—

(A) Section 263(a)(1)(B) is amended by inserting "or 174A" after "174".

(B) Section 263A(c)(2) is amended by inserting "or 174A" after "174".

(8) ACTIVE BUSINESS COMPUTER SOFTWARE ROYALTIES.—Section 543(d)(4)(A)(i) is amended by inserting "174A," after "174,".

(9) SOURCE RULES.—Section 864(g)(2) is amended—

(A) by striking "research and experimental expenditures within the meaning of section 174" in the first sentence and inserting "foreign research or experimental expenditures within the meaning of section 174 or domestic research or experimental expenditures within the meaning of section 174A", and

(B) in the last sentence—

(i) by striking "treated as deferred expenses under subsection (b) of section 174" and inserting "allowed as an amortization deduction under section 174(a) or section 174A(c),", and

(ii) by striking "such subsection" and inserting "such section (as the case may be)".

(10) BASIS ADJUSTMENT.—Section 1016(a)(14) is amended by striking "deductions as deferred expenses under section 174(b)(1) (relating to research and experimental expenditures)" and inserting "deductions under section 174 or 174A(c)".

(11) SMALL BUSINESS STOCK.—Section 1202(e)(2)(B) is amended by striking "which may be treated as research and experimental expenditures under section 174" and inserting "which are treated as foreign research or experimental expenditures under section 174 or domestic research or experimental expenditures under section 174A".

(c) CHANGE IN METHOD OF ACCOUNTING.—

(1) IN GENERAL.—The amendments made by subsection (a) shall be treated as a change in method of accounting for purposes of section 481 of the Internal Revenue Code of 1986 and—

(A) such change shall be treated as initiated by the taxpayer,

(B) such change shall be treated as made with the consent of the Secretary, and

(C) such change shall be applied only on a cut-off basis for any domestic research or experimental expenditures (as defined in section 174A(b) of such Code (as added by this section) and determined by applying the rules of section 174A(d) of such Code) paid or incurred in taxable years beginning after December 31, 2024, and no adjustments under section 481(a) shall be made.

(2) SPECIAL RULES.—In the case of a taxable year which begins after December 31, 2024, and ends before the date of the enactment of this Act—

(A) paragraph (1)(C) shall not apply, and

(B) the change in method of accounting under paragraph (1) shall be applied on a modified cut-off basis, taking into account for purposes of section 481(a) of such Code only the domestic research or experimental expenditures (as defined in section 174A(b) of such Code (as added by this section) and determined by applying the rules of section 174A(d) of such Code) paid or incurred in such taxable year but not allowed as a deduction in such taxable year.

(d) CLERICAL AMENDMENT.—The table of sections for part VI of subchapter B of chapter 1 is amended by inserting after the item relating to section 174 the following new item:

"Sec. 174A. Domestic research or experimental expenditures.".

(e) EFFECTIVE DATE.—

(1) IN GENERAL.—Except as otherwise provided in this subsection or subsection (f)(1), the amendments made by this section shall apply to amounts paid or incurred in taxable years beginning after December 31, 2024.

(2) TREATMENT OF FOREIGN RESEARCH OR EXPERIMENTAL EXPENDITURES UPON DISPOSITION.—

(A) IN GENERAL.—The amendment by subsection (b)(1)(C)(ii) shall apply to property disposed, retired, or abandoned after May 12, 2025.

(B) NO INFERENCE.—The amendment made by subsection (b)(1)(C)(ii) shall not be construed to create any inference with respect to the proper application of section 174(d) of the Internal Revenue Code of 1986 with respect to taxable years beginning before May 13, 2025.

(3) COORDINATION WITH RESEARCH CREDIT.—The amendment made by subsection (b)(2)(B) shall apply to taxable years beginning after December 31, 2024.

(4) NO INFERENCE WITH RESPECT TO COORDINATION WITH RESEARCH CREDIT FOR PRIOR PERIODS.—The amendment made by subsection (b)(2)(B) shall not be construed to create any inference with respect to the proper application of section 280C(c) of the Internal Revenue Code of 1986 with respect to taxable years beginning before January 1, 2025.

(f) TRANSITION RULES.—

(1) ELECTION FOR RETROACTIVE APPLICATION BY CERTAIN SMALL BUSINESSES.—

(A) IN GENERAL.—At the election of an eligible taxpayer, paragraphs (1) and (3) of subsection (e) shall each be applied by substituting "December 31, 2021" for "December 31, 2024". An election made under this subparagraph shall be made in such manner as the Secretary may provide and not later than the date that is 1 year after the date of the enactment of this Act. The taxpayer shall file an amended return for each taxable year affected by such election.

(B) ELIGIBLE TAXPAYER.—For purposes of this paragraph, the term "eligible taxpayer" means any taxpayer (other than a tax shelter prohibited from using the cash receipts and disbursements method of accounting under section 448(a)(3)) which meets the gross receipts test of section 448(c) for the first taxable year beginning after December 31, 2024.

(C) ELECTION TREATED AS CHANGE IN METHOD OF ACCOUNTING.—In the case of any taxpayer which elects the application of subparagraph (A)—

(i) such election may be treated as a change in method of accounting for purposes of section 481 of such Code for the taxpayer's first taxable year affected by such election,

(ii) such change shall be treated as initiated by the taxpayer for such taxable year,

(iii) such change shall be treated as made with the consent of the Secretary, and

(iv) subsection (c) shall not apply to such taxpayer.

(D) ELECTION REGARDING COORDINATION WITH RESEARCH CREDIT.—An election under section 280C(c)(2) of the Internal Revenue Code of 1986 (or revocation of such election) for any taxable year beginning after December 31, 2021, by an eligible taxpayer making an election under subparagraph (A) shall not fail to be treated as timely made (or as made on the return) if made during the 1-year period beginning on the date of the enactment of this Act on an amended return for such taxable year.

(2) ELECTION TO DEDUCT CERTAIN UNAMORTIZED AMOUNTS PAID OR INCURRED IN TAXABLE YEARS BEGINNING BEFORE JANUARY 1, 2025.—

(A) IN GENERAL.—In the case of any domestic research or experimental expenditures (as defined in section 174A, as added by subsection (a)) which are paid or incurred in taxable years beginning after December 31, 2021, and before January 1, 2025, and which was charged to capital account, a taxpayer may elect—

(i) to deduct any remaining unamortized amount with respect to such expenditures in the first taxable year beginning after December 31, 2024, or

(ii) to deduct such remaining unamortized amount with respect to such expenditures ratably over the 2-taxable year period beginning with the first taxable year beginning after December 31, 2024.

(B) CHANGE IN METHOD OF ACCOUNTING.—In the case of a taxpayer who makes an election under this paragraph—

(i) such taxpayer shall be treated as initiating a change in method of accounting for purposes of section 481 of the Internal Revenue Code of 1986 with respect to the expenditures to which the election applies,

(ii) such change shall be treated as made with the consent of the Secretary, and

(iii) such change shall be applied only on a cutoff basis for such expenditures and no adjustments under section 481(a) shall be made.

(C) REGULATIONS.—The Secretary of the Treasury (or the Secretary's delegate) shall publish such guidance or regulations as may be necessary to carry out the purposes of this paragraph, including regulations or guidance allowing for the deduction allowed under subparagraph (A) in the case of taxpayers with taxable years beginning after December 31, 2024, and ending before the date of the enactment of this Act.

SEC. 70303. MODIFICATION OF LIMITATION ON BUSINESS INTEREST.

(a) IN GENERAL.—Section 163(j)(8)(A)(v) is amended by striking "in the case of taxable years beginning before January 1, 2022,".

(b) FLOOR PLAN FINANCING APPLICABLE TO CERTAIN TRAILERS AND CAMPERS.—Section 163(j)(9)(C) is amended by adding at the end the following new flush sentence:

"Such term shall also include any trailer or camper which is designed to provide temporary living quarters for recreational, camping, or seasonal use and is designed to be towed by, or affixed to, a motor vehicle.".

(c) EFFECTIVE DATE AND SPECIAL RULE.—

(1) IN GENERAL.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

(2) SPECIAL RULE FOR SHORT TAXABLE YEARS.—The Secretary of the Treasury (or the Secretary's delegate) may prescribe such rules as are necessary or appropriate to provide for the application of the amendments made by this section in the case of any taxable year of less than 12 months that begins after December 31, 2024, and ends before the date of the enactment of this Act.

SEC. 70304. EXTENSION AND ENHANCEMENT OF PAID FAMILY AND MEDICAL LEAVE CREDIT.

(a) IN GENERAL.—Section 45S is amended—

(1) in subsection (a)—

(A) by striking paragraph (1) and inserting the following:

"(1) IN GENERAL.—For purposes of section 38, in the case of an eligible employer, the paid family and medical leave credit is an amount equal to either of the following (as elected by such employer):

"(A) The applicable percentage of the amount of wages paid to qualifying employees with respect to any period in which such employees are on family and medical leave.

"(B) If such employer has an insurance policy with regards to the provision of paid family and medical leave which is in force during the taxable year, the applicable percentage of the total amount of premiums paid or incurred by such employer during such taxable year with respect to such insurance policy.", and

(B) by adding at the end the following:

"(3) RATE OF PAYMENT DETERMINED WITHOUT REGARD TO WHETHER LEAVE IS TAKEN.—For purposes of determining the applicable percentage with respect to paragraph (1)(B), the rate of payment under the insurance policy shall be determined without regard to whether any qualifying employees were on family and medical leave during the taxable year.",

(2) in subsection (b)(1), by striking "credit allowed" and inserting "wages taken into account",

(3) in subsection (c), by striking paragraphs (3) and (4) and inserting the following:

"(3) AGGREGATION RULE.—

"(A) IN GENERAL.—Except as provided in subparagraph (B), all persons which are treated as a single employer under subsections (b) and (c) of section 414 shall be treated as a single employer.

"(B) EXCEPTION.—

"(i) IN GENERAL.—Subparagraph (A) shall not apply to any person who establishes to the satisfaction of the Secretary that such person has a substantial and legitimate business reason for failing to provide a written policy described in paragraph (1) or (2).

"(ii) SUBSTANTIAL AND LEGITIMATE BUSINESS REASON.—For purposes of clause (i), the term 'substantial and legitimate business reason' shall not include the operation of a separate line of business, the rate of wages or category of jobs for employees (or any similar basis), or the application of State or local laws relating to family and medical leave, but may include the grouping of employees of a common law employer.

"(4) TREATMENT OF BENEFITS MANDATED OR PAID FOR BY STATE OR LOCAL GOVERNMENTS.—For purposes of this section, any leave which is paid by a State or local government or required by State or local law—

"(A) except as provided in subparagraph (B), shall be taken into account in determining the amount of paid family and medical leave provided by the employer, and

"(B) shall not be taken into account in determining the amount of the paid family and medical leave credit under subsection (a).",

(4) in subsection (d)—

(A) in paragraph (1), by inserting "(or, at the election of the employer, for not less than 6 months)" after "1 year or more",

(B) in paragraph (2)—

(i) by inserting ", as determined on an annualized basis (pro-rata for part-time employees)," after "compensation", and

(ii) by striking the period at the end and inserting ", and", and

(C) by adding at the end the following:

"(3) is customarily employed for not less than 20 hours per week.", and

(5) by striking subsection (i).

(b) NO DOUBLE BENEFIT.—Section 280C(a) is amended—

(1) by striking "45S(a)" and inserting "45S(a)(1)(A)", and

(2) by inserting after the first sentence the following: "No deduction shall be allowed for that portion of the premiums paid or incurred for the taxable year which is equal to that portion of the paid family and medical leave credit which is determined for the taxable year under section 45S(a)(1)(B).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70305. EXCEPTIONS FROM LIMITATIONS ON DEDUCTION FOR BUSINESS MEALS.

(a) EXCEPTION TO DENIAL OF DEDUCTION FOR BUSINESS MEALS.—Section 274(o), as added by section 13304 of Public Law 115-97, is amended by striking "No deduction" and inserting "Except in the case of an expense described in subsection (e)(8) or (n)(2)(C), no deduction".

(b) MEALS PROVIDED ON CERTAIN FISHING BOATS AND AT CERTAIN FISH PROCESSING FACILITIES NOT SUBJECT TO 50 PERCENT LIMITATION.—Section 274(n)(2)(C) of the Internal Revenue Code of 1986 is amended by striking "or" at the end of clause (iii) and by adding at the end the following new clause:

"(v) provided—

"(I) on a fishing vessel, fish processing vessel, or fish tender vessel (as such terms are defined in section 2101 of title 46, United States Code), or

"(II) at a facility for the processing of fish for commercial use or consumption which—

"(aa) is located in the United States north of 50 degrees north latitude, and

"(bb) is not located in a metropolitan statistical area (within the meaning of section 143(k)(2)(B)), or".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to amounts paid or incurred after December 31, 2025.

SEC. 70306. INCREASED DOLLAR LIMITATIONS FOR EXPENSING OF CERTAIN DEPRECIABLE BUSINESS ASSETS.

(a) IN GENERAL.—Section 179(b) is amended—

(1) in paragraph (1), by striking "$1,000,000" and inserting "$2,500,000", and

(2) in paragraph (2), by striking "$2,500,000" and inserting "$4,000,000".

(b) CONFORMING AMENDMENTS.—Section 179(b)(6)(A) is amended—

(1) by inserting "(2025 in the case of the dollar amounts in paragraphs (1) and (2))" after "In the case of any taxable year beginning after 2018", and

(2) in clause (ii), by striking "determined by substituting 'calendar year 2017' for 'calendar year 2016' in subparagraph (A)(ii) thereof." and inserting "determined by substituting in subparagraph (A)(ii) thereof— "

"(I) in the case of amounts in paragraphs (1) and (2), 'calendar year 2024' for 'calendar year 2016', and

"(II) in the case of the amount in paragraph (5)(A), 'calendar year 2017' for 'calendar year 2016'.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to property placed in service in taxable years beginning after December 31, 2024.

SEC. 70307. SPECIAL DEPRECIATION ALLOWANCE FOR QUALIFIED PRODUCTION PROPERTY.

(a) IN GENERAL.—Section 168 is amended by adding at the end the following new subsection:

"(n) SPECIAL ALLOWANCE FOR QUALIFIED PRODUCTION PROPERTY.—

"(1) IN GENERAL.—In the case of any qualified production property of a taxpayer making an election under this subsection—

"(A) the depreciation deduction provided by section 167(a) for the taxable year in which such property is placed in service shall include an allowance equal to 100 percent of the adjusted basis of the qualified production property, and

"(B) the adjusted basis of the qualified production property shall be reduced by the amount of such deduction before computing the amount otherwise allowable as a depreciation deduction under this chapter for such taxable year and any subsequent taxable year.

"(2) QUALIFIED PRODUCTION PROPERTY.—For purposes of this subsection—

"(A) IN GENERAL.—The term 'qualified production property' means that portion of any nonresidential real property—

"(i) to which this section applies,

"(ii) which is used by the taxpayer as an integral part of a qualified production activity,

"(iii) which is placed in service in the United States or any possession of the United States,

"(iv) the original use of which commences with the taxpayer,

"(v) the construction of which begins after January 19, 2025, and before January 1, 2029,

"(vi) which is designated by the taxpayer in the election made under this subsection, and

"(vii) which is placed in service before January 1, 2031.

For purposes of clause (ii), in the case of property with respect to which the taxpayer is a lessor, property used by a lessee shall not be considered to be used by the taxpayer as part of a qualified production activity.

"(B) SPECIAL RULE FOR CERTAIN PROPERTY NOT PREVIOUSLY USED IN QUALIFIED PRODUCTION ACTIVITIES.—

"(i) IN GENERAL.—In the case of property acquired by the taxpayer during the period described in subparagraph (A)(v), the requirements of clauses (iv) and (v) of subparagraph (A) shall be treated as satisfied if—

"(I) such property was not used in a qualified production activity (determined without regard to the second sentence of subparagraph (D)) by any person at any time during the period beginning on January 1, 2021, and ending on May 12, 2025,

"(II) such property was not used by the taxpayer at any time prior to such acquisition, and

"(III) the acquisition of such property meets the requirements of paragraphs (2)(A), (2)(B), (2)(C), and (3) of section 179(d).

"(ii) WRITTEN BINDING CONTRACTS.—For purposes of determining under clause (i)—

"(I) whether such property is acquired before the period described in subparagraph (A)(v), such property shall be treated as acquired not later than the date on which the taxpayer enters into a written binding contract for such acquisition, and

"(II) whether such property is acquired after such period, such property shall be treated as acquired not earlier than such date.

"(C) EXCLUSION OF OFFICE SPACE, ETC.—The term 'qualified production property' shall not include that portion of any nonresidential real property which is used for offices, administrative services, lodging, parking, sales activities, research activities, software development or engineering activities, or other functions unrelated to the manufacturing, production, or refining of tangible personal property.

"(D) QUALIFIED PRODUCTION ACTIVITY.—The term 'qualified production activity' means the manufacturing, production, or refining of a qualified product. The activities of any taxpayer do not constitute manufacturing, production, or refining of a qualified product unless the activities of such taxpayer result in a substantial transformation of the property comprising the product.

"(E) PRODUCTION.—The term 'production' shall not include activities other than agricultural production and chemical production.

"(F) QUALIFIED PRODUCT.—The term 'qualified product' means any tangible personal property if such property is not a food or beverage prepared in the same building as a retail establishment in which such property is sold.

"(G) SYNDICATION.—For purposes of subparagraph (A)(iv), rules similar to the rules of subsection (k)(2)(E)(iii) shall apply.

"(H) EXTENSION OF PLACED IN SERVICE DATE UNDER CERTAIN CIRCUMSTANCES.—The Secretary may extend the date under subparagraph (A)(vii) with respect to any property that meets the requirements of clauses (i) through (vi) of subparagraph (A) if the Secretary determines that an act of God (as defined in section 101(1) of the Comprehensive Environmental Response, Compensation, and Liability Act of 1980) prevents the taxpayer from placing such property in service before such date.

"(3) DEDUCTION ALLOWED IN COMPUTING MINIMUM TAX.—For purposes of determining alternative minimum taxable income under section 55, the deduction under section 167 for qualified production property shall be determined under this section without regard to any adjustment under section 56.

"(4) COORDINATION WITH CERTAIN OTHER PROVISIONS.—

"(A) OTHER SPECIAL DEPRECIATION ALLOWANCES.—For purposes of subsections (k)(7), (l)(3)(D), and (m)(2)(B)(iii)—

"(i) qualified production property shall be treated as a separate class of property, and

"(ii) the taxpayer shall be treated as having made an election under such subsections with respect to such class.

"(B) ALTERNATIVE DEPRECIATION PROPERTY.—The term 'qualified production property' shall not include any property to which the alternative depreciation system under subsection (g) applies. For purposes of subsection (g)(7)(A), qualified production property to which this subsection applies shall be treated as separate nonresidential real property.

"(5) RECAPTURE.—If, at any time during the 10-year period beginning on the date that any qualified production property is placed in service by the taxpayer, such property ceases to be used as described in paragraph (2)(A)(ii) and is used by the taxpayer in a productive use not described in paragraph (2)(A)(ii)—

"(A) section 1245 shall be applied—

"(i) by treating such property as having been disposed of by the taxpayer as of the first time such property is so used in a productive use not described in paragraph (2)(A)(ii), and

"(ii) by treating the amount described in subparagraph (B) of section 1245(a)(1) with respect to such disposition as being not less than the amount described in subparagraph (A) of such section, and

"(B) the basis of the taxpayer in such property, and the taxpayer's allowance for depreciation with respect to such property, shall be appropriately adjusted to take into account amounts recognized by reason of subparagraph (A).

"(6) ELECTION.—

"(A) IN GENERAL.—An election under this subsection for any taxable year shall—

"(i) specify the nonresidential real property subject to the election and the portion of such property designated under paragraph (2)(A)(vi), and

"(ii) except as otherwise provided by the Secretary, be made on the taxpayer's return of the tax imposed by this chapter for the taxable year.

Such election shall be made in such manner as the Secretary may prescribe by regulations or other guidance.

"(B) ELECTION.—Any election made under this subsection, and any specification contained in any such election, may not be revoked except with the consent of the Secretary (and the Secretary shall provide such consent only in extraordinary circumstances).

"(7) REGULATIONS.—The Secretary shall issue such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this subsection, including regulations or other guidance—

"(A) providing rules for regarding what constitutes substantial transformation of property which are consistent with guidance provided under section 954(d), and

"(B) providing for the application of paragraph (5) with respect to a change in use described in such paragraph by a transferee following a fully or partially tax free transfer of qualified production property.".

(b) TREATMENT OF QUALIFIED PRODUCTION PROPERTY AS SECTION 1245 PROPERTY.—Section 1245(a)(3) is amended by striking "or" at the end of subparagraph (E), by striking the period at the end of subparagraph (F) and inserting ", or", and by adding at the end the following new subparagraph:

"(G) any qualified production property (as defined in section 168(n)(2)).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to property placed in service after the date of the enactment of this Act.

SEC. 70308. ENHANCEMENT OF ADVANCED MANUFACTURING INVESTMENT CREDIT.

(a) IN GENERAL.—Section 48D(a) is amended by striking "25 percent" and inserting "35 percent".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to property placed in service after December 31, 2025.

SEC. 70309. SPACEPORTS ARE TREATED LIKE AIRPORTS UNDER EXEMPT FACILITY BOND RULES.

(a) IN GENERAL.—Section 142(a)(1) is amended to read as follows:

"(1) airports and spaceports,".

(b) TREATMENT OF GROUND LEASES.—Section 142(b)(1) is amended by adding at the end the following new subparagraph:

"(C) SPECIAL RULE FOR SPACEPORT GROUND LEASES.—For purposes of subparagraph (A), spaceport property located on land leased by a governmental unit from the United States shall not fail to be treated as owned by a governmental unit if the requirements of this paragraph are met by the lease and any subleases of the property.".

(c) DEFINITION OF SPACEPORT.—Section 142 is amended by adding at the end the following new subsection:

"(p) SPACEPORT.—

"(1) IN GENERAL.—For purposes of subsection (a)(1), the term 'spaceport' means any facility located at or in close proximity to a launch site or reentry site used for—

"(A) manufacturing, assembling, or repairing spacecraft, space cargo, other facilities described in this paragraph, or any component of the foregoing,

"(B) flight control operations,

"(C) providing launch services and reentry services, or

"(D) transferring crew, spaceflight participants, or space cargo to or from spacecraft.

"(2) ADDITIONAL TERMS.—For purposes of paragraph (1)—

"(A) SPACE CARGO.—The term 'space cargo' includes satellites, scientific experiments, other property transported into space, and any other type of payload, whether or not such property returns from space.

"(B) SPACECRAFT.—The term 'spacecraft' means a launch vehicle or a reentry vehicle.

"(C) OTHER TERMS.—The terms 'launch site', 'crew', 'space flight participant', 'launch services', 'launch vehicle', 'payload', 'reentry services', 'reentry site', a 'reentry vehicle' shall have the respective meanings given to such terms by section 50902 of title 51, United States Code (as in effect on the date of enactment of this subsection).

"(3) PUBLIC USE REQUIREMENT.—A facility shall not be required to be available for use by the general public to be treated as a spaceport for purposes of this section.

"(4) MANUFACTURING FACILITIES AND INDUSTRIAL PARKS ALLOWED.—With respect to spaceports, subsection (c)(2)(E) shall not apply to spaceport property described in paragraph (1)(A).".

(d) EXCEPTION FROM FEDERALLY GUARANTEED BOND PROHIBITION.—Section 149(b)(3) is amended by adding at the end the following new subparagraph:

"(F) EXCEPTION FOR SPACEPORTS.—A bond shall not be treated as federally guaranteed merely because of the payment of rent, user fees, or other charges by the United States (or any agency or instrumentality thereof) in exchange for the use of the spaceport by the United States (or any agency or instrumentality thereof).".

(e) CONFORMING AMENDMENT.—The heading for section 142(c) is amended by inserting "SPACEPORTS," after "AIRPORTS,".

(f) EFFECTIVE DATE.—The amendments made by this section shall apply to obligations issued after the date of the enactment of this Act.

Subchapter B—Permanent America-first International Tax Reforms

PART I—FOREIGN TAX CREDIT

SEC. 70311. MODIFICATIONS RELATED TO FOREIGN TAX CREDIT LIMITATION.

(a) RULES FOR ALLOCATION OF CERTAIN DEDUCTIONS TO FOREIGN SOURCE NET CFC TESTED INCOME FOR PURPOSES OF FOREIGN TAX CREDIT LIMITATION.—Section 904(b) is amended by adding at the end the following new paragraph:

"(5) DEDUCTIONS TREATED AS ALLOCABLE TO FOREIGN SOURCE NET CFC TESTED INCOME.—Solely for purposes of the application of subsection (a) with respect to amounts described in subsection (d)(1)(A), the taxpayer's taxable income from sources without the United States shall be determined by allocating and apportioning—

"(A) any deduction allowed under section 250(a)(1)(B) (and any deduction allowed under section 164(a)(3) for taxes imposed on amounts described in section 250(a)(1)(B)) to such income,

"(B) no amount of interest expense or research and experimental expenditures to such income, and

"(C) any other deduction to such income only if such deduction is directly allocable to such income.

Any amount or deduction which would (but for subparagraphs (B) and (C)) have been allocated or apportioned to such income shall only be allocated or apportioned to income which is from sources within the United States.".

(b) OTHER MODIFICATIONS.—

(1) Section 904(d)(2)(H)(i) is amended by striking "paragraph (1)(B)" and inserting "paragraph (1)(D)".

(2) Section 904(d)(4)(C)(ii) is amended by striking "paragraph (1)(A)" and inserting "paragraph (1)(C)".

(3) Section 951A(f)(1)(A) is amended by striking "904(h)(1)" and inserting "904(h)".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70312. MODIFICATIONS TO DETERMINATION OF DEEMED PAID CREDIT FOR TAXES PROPERLY ATTRIBUTABLE TO TESTED INCOME.

(a) INCREASE IN DEEMED PAID CREDIT.—

(1) IN GENERAL.—Section 960(d)(1) is amended by striking "80 percent" and inserting "90 percent".

(2) GROSS UP FOR DEEMED PAID FOREIGN TAX CREDIT.—Section 78 is amended—

(A) by striking "subsections (a), (b), and (d)" and inserting "subsections (a) and (d)", and

(B) by striking "80 percent" and inserting "90 percent".

(b) DISALLOWANCE OF FOREIGN TAX CREDIT WITH RESPECT TO DISTRIBUTIONS OF PREVIOUSLY TAXED NET CFC TESTED INCOME.—Section 960(d) is amended by adding at the end the following new paragraph:

"(4) DISALLOWANCE OF FOREIGN TAX CREDIT WITH RESPECT TO DISTRIBUTIONS OF PREVIOUSLY TAXED NET CFC TESTED INCOME.—No credit shall be allowed under section 901 for 10 percent of any foreign income taxes paid or accrued (or deemed paid under subsection (b)(1)) with respect to any amount excluded from gross income under section 959(a) by reason of an inclusion in gross income under section 951A(a).".

(c) EFFECTIVE DATES.—

(1) IN GENERAL.—The amendments made by subsection (a) shall apply to taxable years beginning after December 31, 2025.

(2) DISALLOWANCE.—The amendment made by subsection (b) shall apply to foreign income taxes paid or accrued (or deemed paid under section 960(b)(1) of the Internal Revenue Code of 1986) with respect to any amount excluded from gross income under section 959(a) of such Code by reason of an inclusion in gross income under section 951A(a) of such Code after June 28, 2025.

SEC. 70313. SOURCING CERTAIN INCOME FROM THE SALE OF INVENTORY PRODUCED IN THE UNITED STATES.

(a) IN GENERAL.—Section 904(b), as amended by section 70311, is amended by adding at the end the following new paragraph:

"(6) SOURCE RULES FOR CERTAIN INVENTORY PRODUCED IN THE UNITED STATES AND SOLD THROUGH FOREIGN BRANCHES.—For purposes of this section, if a United States person maintains an office or other fixed place of business in a foreign country (determined under rules similar to the rules of section 864(c)(5)), the portion of income which—

"(A) is from the sale or exchange outside the United States of inventory property (within the meaning of section 865(i)(1))—

"(i) which is produced in the United States,

"(ii) which is for use outside the United States, and "(iii) to which the third sentence of section 863(b) applies, and

"(B) is attributable (determined under rules similar to the rules of section 864(c)(5)) to such office or other fixed place of business,

shall be treated as from sources without the United States, except that the amount so treated shall not exceed 50 percent of the income from the sale or exchange of such inventory property.".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

PART II—FOREIGN-DERIVED DEDUCTION ELIGIBLE INCOME AND NET CFC TESTED INCOME

SEC. 70321. MODIFICATION OF DEDUCTION FOR FOREIGN-DERIVED DEDUCTION ELIGIBLE INCOME AND NET CFC TESTED INCOME.

(a) IN GENERAL.—Section 250(a) is amended—

(1) by striking "37.5 percent" in paragraph (1)(A) and inserting "33.34 percent",

(2) by striking "50 percent" in paragraph (1)(B) and inserting "40 percent", and

(3) by striking paragraph (3).

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70322. DETERMINATION OF DEDUCTION ELIGIBLE INCOME.

(a) SALES OR OTHER DISPOSITIONS OF CERTAIN PROPERTY.—

(1) IN GENERAL.—Section 250(b)(3)(A)(i) is amended—

(A) by striking "and" at the end of subclause (V),

(B) by striking "over" at the end of subclause (VI) and inserting "and", and

(C) by adding at the end the following new subclause:

"(VII) except as otherwise provided by the Secretary, any income and gain from the sale or other disposition (including pursuant to the deemed sale or other deemed disposition or a transaction subject to section 367(d)) of—

"(aa) intangible property (as defined in section 367(d)(4)), and

"(bb) any other property of a type that is subject to depreciation, amortization, or depletion by the seller, over".

(2) CONFORMING AMENDMENT.—Section 250(b)(5)(E) is amended by inserting "(other than paragraph (3)(A)(i)(VII))" after "For purposes of this subsection".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall apply to sales or other dispositions (including pursuant to deemed sales or other deemed dispositions or a transaction subject to section 367(d) of the Internal Revenue Code of 1986) occurring after June 16, 2025.

(b) EXPENSE APPORTIONMENT LIMITED TO PROPERLY ALLOCABLE EXPENSES.—

(1) IN GENERAL.—Section 250(b)(3)(A)(ii) is amended to read as follows:

"(ii) expenses and deductions (including taxes), other than interest expense and research or experimental expenditures, properly allocable to such gross income.".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to taxable years beginning after December 31, 2025.

SEC. 70323. RULES RELATED TO DEEMED INTANGIBLE INCOME.

(a) TAXATION OF NET CFC TESTED INCOME.—

(1) IN GENERAL.—Section 951A(a) is amended by striking "global intangible low-taxed income" and inserting "net CFC tested income".

(2) REPEAL OF TAX-FREE DEEMED RETURN ON FOREIGN INVESTMENTS.—Section 951A, as amended by the preceding provisions of this Act, is amended by striking subsections (b) and (d) and by redesignating subsections (c), (e), and (f) as subsections (b), (c), and (d), respectively.

(3) CONFORMING AMENDMENTS.—

(A)(i) Section 250 is amended by striking "global intangible low-taxed income" each place it appears in subsections (a)(1)(B)(i), (a)(2), and (b)(3)(A)(i)(II) and inserting "net CFC tested income".

(ii) The heading for section 250 of such Code is amended by striking "**GLOBAL INTANGIBLE LOW-TAXED INCOME**" and inserting "**NET CFC TESTED INCOME**".

(iii) The item relating to section 250 in the table of sections for part VII of subchapter B of chapter 1 of such Code is amended by striking "global intangible low-taxed income" and inserting "net CFC tested income".

(B) Section 951A(c)(1), as redesignated by paragraph (2), is amended by striking "subsections (b), (c)(1)(A), and (c)(1)(B)" and inserting "subsections (b)(1)(A) and (b)(1)(B)".

(C) Section 951A(d), as redesignated by paragraph (2), is amended—

(i) by striking "global intangible low-taxed income" each place it appears and inserting "net CFC tested income", and

(ii) by striking "subsection (c)(1)(A)" in paragraph (2)(B)(ii) and inserting "subsection (b)(1)(A)".

(D) Section 960(d)(2) is amended—

(i) by striking "global intangible low-taxed income" in subparagraph (A) and inserting "net CFC tested income", and

(ii) by striking "section 951A(c)(1)(A)" in subparagraph (B) and inserting "section 951A(b)(1)(A)".

(E)(i) The heading for section 951A is amended by striking "**GLOBAL INTANGIBLE LOW-TAXED INCOME**" and inserting "**NET CFC TESTED INCOME**".

(ii) The item relating to section 951A in the table of sections for subpart F of part III of subchapter N of chapter 1 is amended by striking "Global intangible low-taxed income" and inserting "Net CFC tested income".

(b) DEDUCTION FOR FOREIGN-DERIVED DEDUCTION ELIGIBLE INCOME.—

(1) IN GENERAL.—Section 250(a)(1)(A) is amended by striking "foreign-derived intangible income" and inserting "foreign-derived deduction eligible income".

(2) CONFORMING AMENDMENTS.—

(A) Section 250(a)(2) is amended by striking "foreign-derived intangible income" each place it appears and inserting "foreign-derived deduction eligible income".

(B) Section 250(b), as amended by subsection (a), is amended—

(i) by striking paragraphs (1) and (2),

(ii) by redesignating paragraphs (4) and (5) as paragraphs (1) and (2), respectively, and by moving such paragraphs before paragraph (3),

(iii) in paragraph (2)(B)(ii), as so redesignated, by striking "paragraph (4)(B)" and inserting "paragraph (1)(B)", and

(iv) by striking "INTANGIBLE" in the heading thereof and inserting "DEDUCTION ELIGIBLE".

(C)(i) The heading for section 250 is amended by striking "**INTANGIBLE**" in the heading thereof and inserting "**DEDUCTION ELIGIBLE**".

(ii) The heading for section 172(d)(9) is amended by striking "INTANGIBLE" and inserting "DEDUCTION ELIGIBLE".

(iii) The item relating to section 250 in the table of sections for part VIII of subchapter B of chapter 1 is amended by striking "intangible" and inserting "deduction eligible".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

PART III—BASE EROSION MINIMUM TAX

SEC. 70331. EXTENSION AND MODIFICATION OF BASE EROSION MINIMUM TAX AMOUNT.

(a) IN GENERAL.—Section 59A(b) is amended—

(1) by striking "10 percent" in paragraph (1) and inserting "10.5 percent", and

(2) by striking paragraph (2) and by redesignating paragraphs (3) and (4) as paragraphs (2) and (3), respectively.

(b) CONFORMING AMENDMENTS.—

(1) Section 59A(b)(1) is amended by striking "Except as provided in paragraphs (2) and (3)" and inserting "Except as provided in paragraph (2)".

(2) Section 59A(b)(2), as redesignated by subsection (a)(2), is amended by striking "the percentage otherwise in effect under paragraphs (1)(A) and (2)(A) shall each be increased" and inserting "the percentages otherwise in effect under paragraph (1)(A) shall be increased".

(3) Section 59A(e)(1)(C) is amended by striking "in the case of a taxpayer described in subsection (b)(3)(B)" and inserting "in the case of a taxpayer described in subsection (b)(2)(B)".

(c) OTHER MODIFICATIONS.—

(1) Section 59A(b)(2)(B)(ii), as redesignated by subsection (a)(2), is amended by striking "registered securities dealer" and inserting "securities dealer registered".

(2) Section 59A(h)(2)(B) is amended by striking "section 6038B(b)(2)" and inserting "section 6038A(b)(2)".

(3) Section 59A(i)(2) is amended—

(A) by striking "subsection (g)" and inserting "subsection (h)", and

(B) by striking "subsection (g)(3)" and inserting "subsection (h)(3)".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

PART IV—BUSINESS INTEREST LIMITATION

SEC. 70341. COORDINATION OF BUSINESS INTEREST LIMITATION WITH INTEREST CAPITALIZATION PROVISIONS.

(a) IN GENERAL.—Section 163(j) is amended by redesignating paragraphs (10) and (11) as paragraphs (11) and (12) and by inserting after paragraph (9) the following:

"(10) COORDINATION WITH INTEREST CAPITALIZATION PROVISIONS.—

"(A) IN GENERAL.—In applying this subsection—

"(i) the limitation under paragraph (1) shall apply to business interest without regard to whether the taxpayer would otherwise deduct such business interest or capitalize such business interest under an interest capitalization provision, and

"(ii) any reference in this subsection to a deduction for business interest shall be treated as including a reference to the capitalization of business interest.

"(B) AMOUNT ALLOWED APPLIED FIRST TO CAPITALIZED INTEREST.—The amount allowed after taking into account the limitation described in paragraph (1)—

"(i) shall be applied first to the aggregate amount of business interest which would otherwise be capitalized, and

"(ii) the remainder (if any) shall be applied to the aggregate amount of business interest which would be deducted.

"(C) TREATMENT OF DISALLOWED INTEREST CARRIED FORWARD.—No portion of any business interest carried forward under paragraph (2) from any taxable year to any succeeding taxable year shall, for purposes of this title (including any interest capitalization provision which previously applied to such portion) be treated as interest to which an interest capitalization provision applies.

"(D) INTEREST CAPITALIZATION PROVISION.—For purposes of this section, the term 'interest capitalization provision' means any provision of this subtitle under which interest—

"(i) is required to be charged to capital account, or

"(ii) may be deducted or charged to capital account.".

(b) CERTAIN CAPITALIZED INTEREST NOT TREATED AS BUSINESS INTEREST.—Section 163(j)(5) is amended by adding at the end the following new sentence: "Such term shall not include any interest which is capitalized under section 263(g) or 263A(f).".

(c) REGULATORY AUTHORITY.—Section 163(j), as amended by subsection (a), is amended by redesignating paragraphs (11) and (12) as paragraphs (12) and (13) and by inserting after paragraph (10) the following:

"(11) REGULATORY AUTHORITY.—The Secretary shall issue such regulations or guidance as may be necessary or appropriate to carry out the purposes of this subsection, including regulations or guidance to determine which business interest is taken into account under this subsection and section 59A(c)(3).".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70342. DEFINITION OF ADJUSTED TAXABLE INCOME FOR BUSINESS INTEREST LIMITATION.

(a) IN GENERAL.—Subparagraph (A) of section 163(j)(8) is amended—

(1) by striking "and" at the end of clause (iv), and

(2) by adding at the end the following new clause:

"(vi) the amounts included in gross income under sections 951(a), 951A(a), and 78 (and the portion of the deductions allowed under sections 245A(a) (by reason of section 964(e)(4)) and 250(a)(1)(B) by reason of such inclusions), and".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

PART V—OTHER INTERNATIONAL TAX REFORMS

SEC. 70351. PERMANENT EXTENSION OF LOOK-THRU RULE FOR RELATED CONTROLLED FOREIGN CORPORATIONS.

(a) IN GENERAL.—Section 954(c)(6)(C) is amended by striking "and before January 1, 2026,".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years of foreign corporations beginning after December 31, 2025.

SEC. 70352. REPEAL OF ELECTION FOR 1-MONTH DEFERRAL IN DETERMINATION OF TAXABLE YEAR OF SPECIFIED FOREIGN CORPORATIONS.

(a) IN GENERAL.—Section 898(c) is amended by striking paragraph (2) and redesignating paragraph (3) as paragraph (2).

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years of specified foreign corporations beginning after November 30, 2025.

(c) TRANSITION RULE.—

(1) IN GENERAL.—In the case of a corporation that is a specified foreign corporation as of November 30, 2025, such corporation's first taxable year beginning after such date shall end at the same time as the first required year (within the meaning of section 898(c)(1) of the Internal Revenue Code of 1986) ending after such date. If any specified foreign corporation is required by the amendments made by this section to change its taxable year for its first taxable year beginning after November 30, 2025—

(A) such change shall be treated as initiated by such corporation,

(B) such change shall be treated as having been made with the consent of the Secretary, and

(C) the Secretary shall issue regulations or other guidance for allocating foreign taxes that are paid or accrued in such first taxable year and the succeeding taxable year among such taxable years in the manner the Secretary determines appropriate to carry out the purposes of this section.

(2) SECRETARY.—For purposes of this subsection, the term "Secretary" means the Secretary of the Treasury or the Secretary's delegate.

SEC. 70353. RESTORATION OF LIMITATION ON DOWNWARD ATTRIBUTION OF STOCK OWNERSHIP IN APPLYING CONSTRUCTIVE OWNERSHIP RULES.

(a) IN GENERAL.—Section 958(b) is amended—

(1) by inserting after paragraph (3) the following:

"(4) Subparagraphs (A), (B), and (C) of section 318(a)(3) shall not be applied so as to consider a United States person as owning stock which is owned by a person who is not a United States person.", and

(2) by striking "Paragraph (1)" in the last sentence and inserting "Paragraphs (1) and (4)".

(b) FOREIGN CONTROLLED UNITED STATES SHAREHOLDERS.—Subpart F of part III of subchapter N of chapter 1 is amended by inserting after section 951A the following new section:

"SEC. 951B. AMOUNTS INCLUDED IN GROSS INCOME OF FOREIGN CONTROLLED UNITED STATES SHAREHOLDERS.

"(a) IN GENERAL.—In the case of any foreign controlled United States shareholder of a foreign controlled foreign corporation—

"(1) this subpart (other than sections 951A, 951(b), and 957) shall be applied with respect to such shareholder (separately from, and in addition to, the application of this subpart without regard to this section)—

"(A) by substituting 'foreign controlled United States shareholder' for 'United States shareholder' each place it appears therein, and

"(B) by substituting 'foreign controlled foreign corporation' for 'controlled foreign corporation' each place it appears therein, and

"(2) section 951A (and such other provisions of this subpart as provided by the Secretary) shall be applied with respect to such shareholder—

"(A) by treating each reference to 'United States shareholder' in such section as including a reference to such shareholder, and

"(B) by treating each reference to 'controlled foreign corporation' in such section as including a reference to such foreign controlled foreign corporation.

"(b) FOREIGN CONTROLLED UNITED STATES SHAREHOLDER.—For purposes of this section, the term 'foreign controlled United States shareholder' means, with respect to any foreign corporation, any United States person which would be a United States shareholder with respect to such foreign corporation if—

"(1) section 951(b) were applied by substituting 'more than 50 percent' for '10 percent or more', and

"(2) section 958(b) were applied without regard to paragraph (4) thereof.

"(c) FOREIGN CONTROLLED FOREIGN CORPORATION.—For purposes of this section, the term 'foreign controlled foreign corporation' means a foreign corporation, other than a controlled foreign corporation, which would be a controlled foreign corporation if section 957(a) were applied—

"(1) by substituting 'foreign controlled United States shareholders' for 'United States shareholders', and

"(2) by substituting 'section 958(b) (other than paragraph (4) thereof)' for 'section 958(b)'.

"(d) REGULATIONS.—The Secretary shall prescribe such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this section, including regulations or other guidance—

"(1) to treat a foreign controlled United States shareholder or a foreign controlled foreign corporation as a United States shareholder or as a controlled foreign corporation, respectively, for purposes of provisions of this title other than this subpart (including any reporting requirement), and

"(2) with respect to the treatment of foreign controlled foreign corporations that are passive foreign investment companies (as defined in section 1297).".

(c) CLERICAL AMENDMENT.—The table of sections for subpart F of part III of subchapter N of chapter 1 is amended by inserting after the item relating to section 951A the following new item:

"Sec. 951B. Amounts included in gross income of foreign controlled United States shareholders.".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years of foreign corporations beginning after December 31, 2025.

(e) SPECIAL RULE.—

(1) IN GENERAL.—Except to the extent provided by the Secretary of the Treasury (or the Secretary's delegate), the effective date of any amendment to the Internal Revenue Code of 1986 shall be applied by treating references to United States shareholders as including references to foreign controlled United States shareholders, and by treating references to controlled foreign corporations as including references to foreign controlled foreign corporations.

(2) DEFINITIONS.—Any term used in paragraph (1) which is used in subpart F of part III of subchapter N of chapter 1 of the Internal Revenue Code of 1986 (as amended by this section) shall have the meaning given such term in such subpart.

(f) NO INFERENCE.—The amendments made by this section shall not be construed to create any inference with respect to the proper application of any provision of the Internal Revenue Code of 1986 with respect to taxable years beginning before the taxable years to which such amendments apply.

SEC. 70354. MODIFICATIONS TO PRO RATA SHARE RULES.

(a) IN GENERAL.—Subsection (a) of section 951 is amended to read as follows:

"(a) AMOUNTS INCLUDED.—

"(1) IN GENERAL.—If a foreign corporation is a controlled foreign corporation at any time during a taxable year of the foreign corporation (in this subsection referred to as the 'CFC year')—

"(A) each United States shareholder which owns (within the meaning of section 958(a)) stock in such corporation on any day during the CFC year shall include in gross income such shareholder's pro rata share (determined under paragraph (2)) of the corporation's subpart F income for the CFC year, and

"(B) each United States shareholder which owns (within the meaning of section 958(a)) stock in such corporation on the last day, in the CFC year, on which such corporation is a controlled foreign corporation shall include in gross income the amount determined under section 956 with respect to such shareholder for the CFC year (but only to the extent not excluded from gross income under section 959(a)(2)).

"(2) PRO RATA SHARE OF SUBPART F INCOME.—A United States shareholder's pro rata share of a controlled foreign corporation's subpart F income for a CFC year shall be the portion of such income which is attributable to—

"(A) the stock of such corporation owned (within the meaning of section 958(a)) by such shareholder, and

"(B) any period of the CFC year during which—

"(i) such shareholder owned (within the meaning of section 958(a)) such stock,

"(ii) such shareholder was a United States shareholder of such corporation, and

"(iii) such corporation was a controlled foreign corporation.

"(3) TAXABLE YEAR OF INCLUSION.—Any amount required to be included in gross income by a United States shareholder under paragraph (1) with respect to a CFC year shall be included in gross income for the shareholder's taxable year which includes the last day on which the shareholder owns (within the meaning of section 958(a)) stock in the controlled foreign corporation during such CFC year.

"(4) REGULATORY AUTHORITY.—The Secretary shall prescribe such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this subsection, including regulations or other guidance allowing taxpayers to elect, or requiring taxpayers, to close the taxable year of a controlled foreign corporation upon a direct or indirect disposition of stock of such corporation.".

(b) COORDINATION WITH SECTION 951A.—

(1) TESTED INCOME.—Section 951A(b), as redesignated by section 70323(a)(2), is amended—

(A) in paragraph (1)(A), by striking "(determined for each taxable year of such controlled foreign corporation which ends in or with such taxable year of such United States shareholder)", and

(B) in paragraph (1)(B), by striking "(determined for each taxable year of such controlled foreign corporation which ends in or with such taxable year of such United States shareholder)".

(2) PRO RATA SHARE.—Section 951A(c), as redesignated by section 70323(a)(2), is amended—

(A) in paragraph (1), by striking "in which or with which the taxable year of the controlled foreign corporation ends" and inserting "determined under section 951(a)(3)", and

(B) in paragraph (2), by striking "the last day in the taxable year of such foreign corporation on which such foreign corporation is a controlled foreign corporation" and inserting "any day in such taxable year".

(c) EFFECTIVE DATES.—

(1) IN GENERAL.—The amendments made by this section shall apply to taxable years of foreign corporations beginning after December 31, 2025.

(2) TRANSITION RULE FOR DIVIDENDS.—Except to the extent provided by the Secretary of the Treasury (or the Secretary's delegate), a dividend paid (or deemed paid) by a controlled foreign corporation shall not be treated as a dividend for purposes of applying section 951(a)(2)(B) of the Internal Revenue Code of 1986 (as in effect before the amendments made by this section) if—

(A) such dividend—

(i) was paid (or deemed paid) on or before June 28, 2025, during the taxable year of such controlled foreign corporation which includes such date and the United States shareholder described in section 951(a)(1) of such Code (as so in effect) did not own (within the meaning of section 958(a) of such Code) the stock of such controlled foreign corporation during the portion of such taxable year on or before June 28, 2025, or

(ii) was paid (or deemed paid) after June 28, 2025, and before such controlled foreign corporation's first taxable year beginning after December 31, 2025, and

(B) such dividend does not increase the taxable income of a United States person that is subject to Federal income tax for the taxable year (including by reason of a dividends received deduction, an exclusion from gross income, or an exclusion from subpart F income).

CHAPTER 4—INVESTING IN AMERICAN FAMILIES, COMMUNITIES, AND SMALL BUSINESSES

Subchapter A—Permanent Investments in Families and Children

SEC. 70401. ENHANCEMENT OF EMPLOYER-PROVIDED CHILD CARE CREDIT.

(a) INCREASE OF AMOUNT OF QUALIFIED CHILD CARE EXPENDITURES TAKEN INTO ACCOUNT.—Section 45F(a)(1) is amended by striking "25 percent" and inserting "40 percent (50 percent in the case of an eligible small business)".

(b) INCREASE OF MAXIMUM CREDIT AMOUNT.—Subsection (b) of section 45F is amended to read as follows:

"(b) DOLLAR LIMITATION.—

"(1) IN GENERAL.—The credit allowable under subsection (a) for any taxable year shall not exceed $500,000 ($600,000 in the case of an eligible small business).

"(2) INFLATION ADJUSTMENT.—In the case of any taxable year beginning after 2026, the $500,000 and $600,000 amounts in paragraph (1) shall each be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.".

(c) ELIGIBLE SMALL BUSINESS.—Section 45F(c) is amended by adding at the end the following new paragraph:

"(4) ELIGIBLE SMALL BUSINESS.—The term 'eligible small business' means a business that meets the gross receipts test of section 448(c), determined—

"(A) by substituting '5-taxable-year' for '3-taxable-year' in paragraph (1) thereof, and

"(B) by substituting '5-year' for '3-year' in paragraph (3)(A) thereof.".

(d) CREDIT ALLOWED FOR THIRD-PARTY INTERMEDIARIES.—Section 45F(c)(1)(A)(iii) is amended by inserting ", or under a contract with an intermediate entity that contracts with one or more qualified child care facilities to provide such child care services" before the period at the end.

(e) TREATMENT OF JOINTLY OWNED OR OPERATED CHILD CARE FACILITY.—Section 45F(c)(2) is amended by adding at the end the following new subparagraph:

"(C) TREATMENT OF JOINTLY OWNED OR OPERATED CHILD CARE FACILITY.—A facility shall not fail to be treated as a qualified child care facility of the taxpayer merely because such facility is jointly owned or operated by the taxpayer and other persons.".

(f) REGULATIONS AND GUIDANCE.—Section 45F is amended by adding at the end the following new subsection:

"(g) REGULATIONS AND GUIDANCE.—The Secretary shall issue such regulations or other guidance as may be necessary to carry out the purposes of this section, including guidance to carry out the purposes of paragraphs (1)(A)(iii) and (2)(C) of subsection (c).".

(g) EFFECTIVE DATE.—The amendments made by this section shall apply to amounts paid or incurred after December 31, 2025.

SEC. 70402. ENHANCEMENT OF ADOPTION CREDIT.

(a) IN GENERAL.—Section 23(a) is amended by adding at the end the following new paragraph:

"(4) PORTION OF CREDIT REFUNDABLE.—So much of the credit allowed under paragraph (1) as does not exceed $5,000 shall be treated as a credit allowed under subpart C and not as a credit allowed under this subpart.".

(b) ADJUSTMENTS FOR INFLATION.—Section 23(h) is amended to read as follows:

"(h) ADJUSTMENTS FOR INFLATION.—

"(1) IN GENERAL.—In the case of a taxable year beginning after December 31, 2002, each of the dollar amounts in paragraphs (3) and (4) of subsection (a) and paragraphs (1) and

(2)(A)(i) of subsection (b) shall be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2001' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

"(2) ROUNDING.—If any amount as increased under paragraph (1) is not a multiple of $10, such amount shall be rounded to the nearest multiple of $10.

"(3) SPECIAL RULE FOR REFUNDABLE PORTION.—In the case of the dollar amount in subsection (a)(4), paragraph (1) shall be applied—

"(A) by substituting '2025' for '2002' in the matter preceding subparagraph (A), and

"(B) by substituting 'calendar year 2024' for 'calendar year 2001' in subparagraph (B) thereof.".

(c) EXCLUSION OF REFUNDABLE PORTION OF CREDIT FROM CARRYFORWARD.—Section 23(c)(1) is amended by striking "credit allowable under subsection (a)" and inserting "portion of the credit allowable under subsection (a) which is allowed under this subpart".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

SEC. 70403. RECOGNIZING INDIAN TRIBAL GOVERNMENTS FOR PURPOSES OF DETERMINING WHETHER A CHILD HAS SPECIAL NEEDS FOR PURPOSES OF THE ADOPTION CREDIT.

(a) IN GENERAL.—Section 23(d)(3) is amended—

(1) in subparagraph (A), by inserting "or Indian tribal government" after "a State", and

(2) in subparagraph (B), by inserting "or Indian tribal government" after "such State".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2024.

SEC. 70404. ENHANCEMENT OF THE DEPENDENT CARE ASSISTANCE PROGRAM.

(a) IN GENERAL.—Section 129(a)(2)(A) is amended by striking "$5,000 ($2,500" and inserting "$7,500 ($3,750".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70405. ENHANCEMENT OF CHILD AND DEPENDENT CARE TAX CREDIT.

(a) IN GENERAL.—Paragraph (2) of section 21(a) is amended to read as follows:

"(2) APPLICABLE PERCENTAGE DEFINED.—For purposes of paragraph (1), the term 'applicable percentage' means 50 percent—

"(A) reduced (but not below 35 percent) by 1 percentage point for each $2,000 or fraction thereof by which the taxpayer's adjusted gross income for the taxable year exceeds $15,000, and

"(B) further reduced (but not below 20 percent) by 1 percentage point for each $2,000 ($4,000 in the case of a joint return) or fraction thereof by which the taxpayer's adjusted gross income for the taxable year exceeds $75,000 ($150,000 in the case of a joint return).''.

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

Subchapter B—Permanent Investments in Students and Reforms to Tax-exempt Institutions

SEC. 70411. TAX CREDIT FOR CONTRIBUTIONS OF INDIVIDUALS TO SCHOLARSHIP GRANTING ORGANIZATIONS.

(a) ALLOWANCE OF CREDIT FOR CONTRIBUTIONS OF INDIVIDUALS TO SCHOLARSHIP GRANTING ORGANIZATIONS.—

(1) IN GENERAL.—Subpart A of part IV of subchapter A of chapter 1 is amended by inserting after section 25E the following new section:

"SEC. 25F. QUALIFIED ELEMENTARY AND SECONDARY EDUCATION SCHOLARSHIPS.

"(a) ALLOWANCE OF CREDIT.—In the case of an individual who is a citizen or resident of the United States (within the meaning of section 7701(a)(9)), there shall be allowed as a credit against the tax imposed by this chapter for the taxable year an amount equal to the aggregate amount of qualified contributions made by the taxpayer during the taxable year.

"(b) LIMITATIONS.—

"(1) IN GENERAL.—The credit allowed under subsection (a) to any taxpayer for any taxable year shall not exceed $1,700.

"(2) REDUCTION BASED ON STATE CREDIT.—The amount allowed as a credit under subsection (a) for a taxable year shall be reduced by the amount allowed as a credit on any State tax return of the taxpayer for qualified contributions made by the taxpayer during the taxable year.

"(c) DEFINITIONS.—For purposes of this section—

"(1) COVERED STATE.—The term 'covered State' means one of the States, or the District of Columbia, that, for a calendar year, voluntarily elects to participate under this section and to identify scholarship granting organizations in the State, in accordance with subsection (g).

"(2) ELIGIBLE STUDENT.—The term 'eligible student' means an individual who—

"(A) is a member of a household with an income which, for the calendar year prior to the date of the application for a scholarship, is not greater than 300 percent of the area median gross income (as such term is used in section 42), and

"(B) is eligible to enroll in a public elementary or secondary school.

"(3) QUALIFIED CONTRIBUTION.—The term 'qualified contribution' means a charitable contribution of cash to a scholarship granting organization that uses the contribution to fund scholarships for eligible students solely within the State in which the organization is listed pursuant to subsection (g).

"(4) QUALIFIED ELEMENTARY OR SECONDARY EDUCATION EXPENSE.—The term 'qualified elementary or secondary education expense' means any expense of an eligible student which is described in section 530(b)(3)(A).

"(5) SCHOLARSHIP GRANTING ORGANIZATION.—The term 'scholarship granting organization' means any organization—

"(A) which—

"(i) is described in section 501(c)(3) and exempt from tax under section 501(a), and

"(ii) is not a private foundation,

"(B) which prevents the co-mingling of qualified contributions with other amounts by maintaining one or more separate accounts exclusively for qualified contributions,

"(C) which satisfies the requirements of subsection (d), and

"(D) which is included on the list submitted for the applicable covered State under subsection (g) for the applicable year.

"(d) REQUIREMENTS FOR SCHOLARSHIP GRANTING ORGANIZATIONS.—

"(1) IN GENERAL.—An organization meets the requirements of this subsection if—

"(A) such organization provides scholarships to 10 or more students who do not all attend the same school,

"(B) such organization spends not less than 90 percent of the income of the organization on scholarships for eligible students,

"(C) such organization does not provide scholarships for any expenses other than qualified elementary or secondary education expenses,

"(D) such organization provides a scholarship to eligible students with a priority for—

"(i) students awarded a scholarship the previous school year, and

"(ii) after application of clause (i), any eligible students who have a sibling who was awarded a scholarship from such organization,

"(E) such organization does not earmark or set aside contributions for scholarships on behalf of any particular student, and

"(F) such organization—

"(i) verifies the annual household income and family size of eligible students who apply for scholarships to ensure such students meet the requirement of subsection (c)(2)(A), and

"(ii) limits the awarding of scholarships to eligible students who are a member of a household for which the income does not exceed the amount established under subsection (c)(2)(A).

"(2) PROHIBITION ON SELF-DEALING.—

"(A) IN GENERAL.—A scholarship granting organization may not award a scholarship to any disqualified person.

"(B) DISQUALIFIED PERSON.—For purposes of this paragraph, a disqualified person shall be determined pursuant to rules similar to the rules of section 4946.

"(e) DENIAL OF DOUBLE BENEFIT.—Any qualified contribution for which a credit is allowed under this section shall not be taken into account as a charitable contribution for purposes of section 170.

"(f) CARRYFORWARD OF UNUSED CREDIT.—

"(1) IN GENERAL.—If the credit allowable under subsection (a) for any taxable year exceeds the limitation imposed by section 26(a) for such taxable year reduced by the sum of the credits allowable under this subpart (other than this section, section 23, and section 25D), such excess shall be carried to the succeeding taxable year and added to the credit allowable under subsection (a) for such taxable year.

"(2) LIMITATION.—No credit may be carried forward under this subsection to any taxable year following the fifth taxable year after the taxable year in which the credit arose. For purposes of the preceding sentence, credits shall be treated as used on a first-in first-out basis.

"(g) STATE LIST OF SCHOLARSHIP GRANTING ORGANIZATIONS.—

"(1) LIST.—

"(A) IN GENERAL.—Not later than January 1 of each calendar year (or, with respect to the first calendar year for which this section applies, as early as practicable), a State that voluntarily elects to participate under this section shall provide to the Secretary a list of the scholarship granting organizations that meet the requirements described in subsection (c)(5) and are located in the State.

"(B) PROCESS.—The election under this paragraph shall be made by the Governor of the State or by such other individual, agency, or entity as is designated under State law to make such elections on behalf of the State with respect to Federal tax benefits.

"(2) CERTIFICATION.—Each list submitted under paragraph (1) shall include a certification that the individual, agency, or entity submitting such list on behalf of the State has the authority to perform this function.

"(h) REGULATIONS AND GUIDANCE.—The Secretary shall issue such regulations or other guidance as the Secretary determines necessary to carry out the purposes of this section, including regulations or other guidance—

"(1) providing for enforcement of the requirements under subsections (d) and (g), and

"(2) with respect to recordkeeping or information reporting for purposes of administering the requirements of this section.".

(2) CONFORMING AMENDMENTS.—

(A) Section 25(e)(1)(C) is amended by striking "and 25D" and inserting "25D, and 25F".

(B) The table of sections for subpart A of part IV of subchapter A of chapter 1 is amended by inserting after the item relating to section 25E the following new item:

"Sec. 25F. Qualified elementary and secondary education scholarships.".

(b) EXCLUSION FROM GROSS INCOME FOR SCHOLARSHIPS FOR QUALIFIED ELEMENTARY OR SECONDARY EDUCATION EXPENSES OF ELIGIBLE STUDENTS.—

(1) IN GENERAL.—Part III of subchapter B of chapter 1 is amended by inserting before section 140 the following new section:

"SEC. 139K. SCHOLARSHIPS FOR QUALIFIED ELEMENTARY OR SECONDARY EDUCATION EXPENSES OF ELIGIBLE STUDENTS.

"(a) IN GENERAL.—In the case of an individual, gross income shall not include any amounts provided to such individual or any dependent of such individual pursuant to a scholarship for qualified elementary or secondary education expenses of an eligible student which is provided by a scholarship granting organization.

"(b) DEFINITIONS.—In this section, the terms 'qualified elementary or secondary education expense', 'eligible student', and 'scholarship granting organization' have the same meaning given such terms under section 25F(c).".

(2) CONFORMING AMENDMENT.—The table of sections for part III of subchapter B of chapter 1 is amended by inserting before the item relating to section 140 the following new item:

"Sec. 139K. Scholarships for qualified elementary or secondary education expenses of eligible students.".

(c) EFFECTIVE DATE.—

(1) IN GENERAL.—Except as otherwise provided in this subsection, the amendments made by this section shall apply to taxable years ending after December 31, 2026.

(2) EXCLUSION FROM GROSS INCOME.—The amendments made by subsection (b) shall apply to amounts received after December 31, 2026, in taxable years ending after such date.

SEC. 70412. EXCLUSION FOR EMPLOYER PAYMENTS OF STUDENT LOANS.

(a) IN GENERAL.—Section 127(c)(1)(B) is amended by striking "in the case of payments made before January 1, 2026,".

(b) INFLATION ADJUSTMENT.—Section 127 is amended—

(1) by redesignating subsection (d) as subsection (e), and

(2) by inserting after subsection (c) the following new subsection:

"(d) INFLATION ADJUSTMENT.—

"(1) IN GENERAL.—In the case of any taxable year beginning after 2026, both of the $5,250 amounts in subsection (a)(2) shall each be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

"(2) ROUNDING.—If any increase under paragraph (1) is not a multiple of $50, such increase shall be rounded to the nearest multiple of $50.".

(c) EFFECTIVE DATE.—The amendment made by this section shall apply to payments made after December 31, 2025.

SEC. 70413. ADDITIONAL EXPENSES TREATED AS QUALIFIED HIGHER EDUCATION EXPENSES FOR PURPOSES OF 529 ACCOUNTS.

(a) IN GENERAL.—

(1) IN GENERAL.—Section 529(c)(7) is amended to read as follows:

"(7) TREATMENT OF ELEMENTARY AND SECONDARY TUITION.—Any reference in this section to the term 'qualified higher education expense' shall include a reference to the following expenses in connection with enrollment or attendance at, or for students enrolled at or attending, an elementary or secondary public, private, or religious school:

"(A) Tuition.

"(B) Curriculum and curricular materials.
"(C) Books or other instructional materials.
"(D) Online educational materials.
"(E) Tuition for tutoring or educational classes outside of the home, including at a tutoring facility, but only if the tutor or instructor is not related to the student and—
"(i) is licensed as a teacher in any State,
"(ii) has taught at an eligible educational institution, or
"(iii) is a subject matter expert in the relevant subject.
"(F) Fees for a nationally standardized norm-referenced achievement test, an advanced placement examination, or any examinations related to college or university admission.
"(G) Fees for dual enrollment in an institution of higher education.
"(H) Educational therapies for students with disabilities provided by a licensed or accredited practitioner or provider, including occupational, behavioral, physical, and speech-language therapies.".
(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to distributions made after the date of the enactment of this Act.
(b) INCREASE IN LIMITATION.—
(1) IN GENERAL.—The last sentence of section 529(e)(3) is amended by striking "$10,000" and inserting "$20,000".
(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to taxable years beginning after December 31, 2025.

SEC. 70414. CERTAIN POSTSECONDARY CREDENTIALING EXPENSES TREATED AS QUALIFIED HIGHER EDUCATION EXPENSES FOR PURPOSES OF 529 ACCOUNTS.

(a) IN GENERAL.—Section 529(e)(3) is amended by adding at the end the following new subparagraph:
"(C) CERTAIN POSTSECONDARY CREDENTIALING EXPENSES.—The term 'qualified higher education expenses' includes qualified postsecondary credentialing expenses (as defined in subsection (f)).".
(b) QUALIFIED POSTSECONDARY CREDENTIALING EXPENSES.—Section 529 is amended by redesignating subsection (f) as subsection (g) and by inserting after subsection (e) the following new subsection:
"(f) QUALIFIED POSTSECONDARY CREDENTIALING EXPENSES.—For purposes of this section—
"(1) IN GENERAL.—The term 'qualified postsecondary credentialing expenses' means—
"(A) tuition, fees, books, supplies, and equipment required for the enrollment or attendance of a designated beneficiary in a recognized postsecondary credential program, or any other expense incurred in connection with enrollment in or attendance at a recognized postsecondary credential program if such expense would, if incurred in connection with enrollment or attendance at an eligible educational institution, be covered under subsection (e)(3)(A),

"(B) fees for testing if such testing is required to obtain or maintain a recognized postsecondary credential, and

"(C) fees for continuing education if such education is required to maintain a recognized postsecondary credential.

"(2) RECOGNIZED POSTSECONDARY CREDENTIAL PROGRAM.—The term 'recognized postsecondary credential program' means any program to obtain a recognized postsecondary credential if—

"(A) such program is included on a State list prepared under section 122(d) of the Workforce Innovation and Opportunity Act (29 U.S.C. 3152(d)),

"(B) such program is listed in the public directory of the Web Enabled Approval Management System (WEAMS) of the Veterans Benefits Administration, or successor directory such program,

"(C) an examination (developed or administered by an organization widely recognized as providing reputable credentials in the occupation) is required to obtain or maintain such credential and such organization recognizes such program as providing training or education which prepares individuals to take such examination, or

"(D) such program is identified by the Secretary, after consultation with the Secretary of Labor, as being a reputable program for obtaining a recognized postsecondary credential for purposes of this subparagraph.

"(3) RECOGNIZED POSTSECONDARY CREDENTIAL.—The term 'recognized postsecondary credential' means—

"(A) any postsecondary employment credential that is industry recognized and is—

"(i) any postsecondary employment credential issued by a program that is accredited by the Institute for Credentialing Excellence, the National Commission on Certifying Agencies, or the American National Standards Institute,

"(ii) any postsecondary employment credential that is included in the Credentialing Opportunities On-Line (COOL) directory of credentialing programs (or successor directory) maintained by the Department of Defense or by any branch of the Armed Forces, or

"(iii) any postsecondary employment credential identified for purposes of this clause by the Secretary, after consultation with the Secretary of Labor, as being industry recognized,

"(B) any certificate of completion of an apprenticeship that is registered and certified with the Secretary of Labor under the Act of August 16, 1937 (commonly known as the 'National Apprenticeship Act'; 50 Stat. 664, chapter 663; 29 U.S.C. 50 et seq.),

"(C) any occupational or professional license issued or recognized by a State or the Federal Government (and any certification that satisfies a condition for obtaining such a license), and

"(D) any recognized postsecondary credential as defined in section 3(52) of the Workforce Innovation and Opportunity Act (29 U.S.C. 3102(52)), provided through a program described in paragraph (2)(A).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to distributions made after the date of the enactment of this Act.

SEC. 70415. MODIFICATION OF EXCISE TAX ON INVESTMENT INCOME OF CERTAIN PRIVATE COLLEGES AND UNIVERSITIES.

(a) IN GENERAL.—Section 4968 is amended to read as follows:

"SEC. 4968. EXCISE TAX BASED ON INVESTMENT INCOME OF PRIVATE COLLEGES AND UNIVERSITIES.

"(a) TAX IMPOSED.—There is hereby imposed on each applicable educational institution for the taxable year a tax equal to the applicable percentage of the net investment income of such institution for the taxable year.

"(b) APPLICABLE PERCENTAGE.—For purposes of this section, the term 'applicable percentage' means—

"(1) 1.4 percent in the case of an institution with a student adjusted endowment of at least $500,000, and not in excess of $750,000,

"(2) 4 percent in the case of an institution with a student adjusted endowment in excess of $750,000, and not in excess of $2,000,000, and

"(3) 8 percent in the case of an institution with a student adjusted endowment in excess of $2,000,000.

"(c) APPLICABLE EDUCATIONAL INSTITUTION.—For purposes of this subchapter, the term 'applicable educational institution' means an eligible educational institution (as defined in section 25A(f)(2))—

"(1) which had at least 3,000 tuition-paying students during the preceding taxable year,

"(2) more than 50 percent of the tuition-paying students of which are located in the United States,

"(3) the student adjusted endowment of which is at least $500,000, and

"(4) which is not described in the first sentence of section 511(a)(2)(B) (relating to State colleges and universities).

"(d) STUDENT ADJUSTED ENDOWMENT.—For purposes of this section, the term 'student adjusted endowment' means, with respect to any institution for any taxable year—

"(1) the aggregate fair market value of the assets of such institution (determined as of the end of the preceding taxable year), other than those assets which are used directly in carrying out the institution's exempt purpose, divided by

"(2) the number of students of such institution.

"(e) DETERMINATION OF NUMBER OF STUDENTS.—For purposes of subsections (c) and (d), the number of students of an institution (including for purposes of determining the number of students at a particular location) shall be based on the daily average number of full-time students attending such institution (with part-time students taken into account on a full-time student equivalent basis).

"(f) NET INVESTMENT INCOME.—For purposes of this section—

"(1) IN GENERAL.—Net investment income shall be determined under rules similar to the rules of section 4940(c).

"(2) OVERRIDE OF CERTAIN REGULATORY EXCEPTIONS.—

"(A) STUDENT LOAN INTEREST.—Net investment income shall be determined by taking into account any interest income from a student loan made by the applicable educational institution (or any related organization) as gross investment income.

"(B) FEDERALLY-SUBSIDIZED ROYALTY INCOME.—

"(i) IN GENERAL.—Net investment income shall be determined by taking into account any Federally-subsidized royalty income as gross investment income.

"(ii) FEDERALLY-SUBSIDIZED ROYALTY INCOME.—For purposes of this subparagraph—

"(I) IN GENERAL.—The term 'Federally-subsidized royalty income' means any otherwise-regulatory-exempt royalty income if any Federal funds were used in the research, development, or creation of the patent, copyright, or other intellectual or intangible property from which such royalty income is derived.

"(II) OTHERWISE-REGULATORY-EXEMPT ROYALTY INCOME.—For purposes of this subparagraph, the term 'otherwise-regulatory-exempt royalty income' means royalty income which (but for this subparagraph) would not be taken into account as gross investment income by reason of being derived from patents, copyrights, or other intellectual or intangible property which resulted from the work of students or faculty members in their capacities as such with the applicable educational institution.

"(III) FEDERAL FUNDS.—The term 'Federal funds' includes any grant made by, and any payment made under any contract with, any Federal agency to the applicable educational institution, any related organization, or any student or faculty member referred to in subclause (II).

"(g) ASSETS AND NET INVESTMENT INCOME OF RELATED ORGANIZATIONS.—

"(1) IN GENERAL.—For purposes of subsections (d) and (f), assets and net investment income of any related organization with respect to an educational institution shall be treated as assets and net investment income, respectively, of the educational institution, except that—

"(A) no such amount shall be taken into account with respect to more than 1 educational institution, and

"(B) unless such organization is controlled by such institution or is described in section 509(a)(3) with respect to such institution for the taxable year, assets and net investment income which are not intended or available for the use or benefit of the educational institution shall not be taken into account.

"(2) RELATED ORGANIZATION.—For purposes of this subsection, the term 'related organization' means, with respect to an educational institution, any organization which—

"(A) controls, or is controlled by, such institution,

"(B) is controlled by 1 or more persons which also control such institution, or

"(C) is a supported organization (as defined in section 509(f)(3)), or an organization described in section 509(a)(3), during the taxable year with respect to such institution.

"(h) REGULATIONS.—The Secretary shall prescribe such regulations or other guidance as may be necessary to prevent avoidance of the tax under this section, including regulations or other guidance to prevent avoidance of such tax through the restructuring of endowment funds or other arrangements designed to reduce or eliminate the value of net investment income or assets subject to the tax imposed by this section.".

(b) REQUIREMENT TO REPORT CERTAIN INFORMATION WITH RESPECT TO APPLICATION OF EXCISE TAX BASED ON INVESTMENT INCOME OF PRIVATE COLLEGES AND UNIVERSITIES.—Section 6033 is amended by redesignating subsection (o) as subsection (p) and by inserting after subsection (n) the following new subsection:

"(o) REQUIREMENT TO REPORT CERTAIN INFORMATION WITH RESPECT TO EXCISE TAX BASED ON INVESTMENT INCOME OF PRIVATE COLLEGES AND UNIVERSITIES.—Each applicable educational institution described in section 4968(c) which is subject to the requirements of subsection (a) shall include on the return required under subsection (a)—

"(1) the number of tuition-paying students taken into account under section 4968(c), and

"(2) the number of students of such institution (determined under the rules of section 4968(e)).".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70416. EXPANDING APPLICATION OF TAX ON EXCESS COMPENSATION WITHIN TAX-EXEMPT ORGANIZATIONS.

(a) IN GENERAL.—Section 4960(c)(2) is amended to read as follows:

"(2) COVERED EMPLOYEE.—For purposes of this section, the term 'covered employee' means any employee of an applicable tax-exempt organization (or any predecessor of such an organization) and any former employee of such an organization (or predecessor) who was such an employee during any taxable year beginning after December 31, 2016.".

(b) EFFECTIVE DATE.—The amendment made by subsection (a) shall apply to taxable years beginning after December 31, 2025.

Subchapter C—Permanent Investments in Community Development

SEC. 70421. PERMANENT RENEWAL AND ENHANCEMENT OF OPPORTUNITY ZONES.

(a) DECENNIAL DESIGNATIONS.—

(1) DETERMINATION PERIOD.—Section 1400Z-1(c)(2)(B) is amended by striking "beginning on the date of the enactment of the Tax Cuts and Jobs Act" and inserting "beginning on the decennial determination date".

(2) DECENNIAL DETERMINATION DATE.—Section 1400Z-1(c)(2) is amended by adding at the end the following new subparagraph:

"(C) DECENNIAL DETERMINATION DATE.—The term 'decennial determination date' means—

"(i) July 1, 2026, and

"(ii) each July 1 of the year that is 10 years after the preceding decennial determination date under this subparagraph.".

(3) REPEAL OF SPECIAL RULE FOR PUERTO RICO.—Section 1400Z-1(b) is amended by striking paragraph (3).

(4) LIMITATION ON NUMBER OF DESIGNATIONS.—Section 1400Z-1(d)(1) is amended—

(A) in paragraph (1)—

(i) by striking "and subsection (b)(3)", and

(ii) by inserting "during any period" after "the number of population census tracts in a State that may be designated as qualified opportunity zones under this section", and

(B) in paragraph (2), by inserting "during any period" before the period at the end.

(5) EFFECTIVE DATES.—

(A) IN GENERAL.—Except as provided in subparagraph (B), the amendments made by this subsection shall take effect on the date of the enactment of this Act.

(B) PUERTO RICO.—The amendment made by paragraph (3) shall take effect on December 31, 2026.

(b) QUALIFICATION FOR DESIGNATIONS.—

(1) DETERMINATION OF LOW-INCOME COMMUNITIES.—Section 1400Z-1(c) is amended by striking all that precedes paragraph (2) and inserting the following:

"(c) OTHER DEFINITIONS.—For purposes of this section—

"(1) LOW-INCOME COMMUNITIES.—The term 'low-income community' means any population census tract if—

"(A) such population census tract has a median family income that—

"(i) in the case of a population census tract not located within a metropolitan area, does not exceed 70 percent of the statewide median family income, or

"(ii) in the case of a population census tract located within a metropolitan area, does not exceed 70 percent of the metropolitan area median family income, or

"(B) such population census tract—

"(i) has a poverty rate of at least 20 percent, and

"(ii) has a median family income that—

"(I) in the case of a population census tract not located within a metropolitan area, does not exceed 125 percent of the statewide median family income, or

"(II) in the case of a population census tract located within a metropolitan area, does not exceed 125 percent of the metropolitan area median family income.".

(2) REPEAL OF RULE FOR CONTIGUOUS CENSUS TRACTS.—Section 1400Z-1 is amended by striking subsection (e) and by redesignating subsection (f) as subsection (e).

(3) PERIOD FOR WHICH DESIGNATION IS IN EFFECT.—Section 1400Z-1(e), as redesignated by paragraph (2), is amended to read as follows:

"(e) PERIOD FOR WHICH DESIGNATION IS IN EFFECT.—

"(1) IN GENERAL.—A designation as a qualified opportunity zone shall remain in effect for the period beginning on the applicable start date and ending on the day before the date that is 10 years after the applicable start date.

"(2) APPLICABLE START DATE.—For purposes of this section, the term 'applicable start date' means, with respect to any qualified opportunity zone designated under this section, the

January 1 following the date on which such qualified opportunity zone was certified and designated by the Secretary under subsection (b)(1)(B).''.

(4) EFFECTIVE DATE.—The amendments made by this subsection shall apply to areas designated under section 1400Z-1 of the Internal Revenue Code of 1986 after the date of the enactment of this Act.

(c) APPLICATION OF SPECIAL RULES FOR CAPITAL GAINS.—

(1) REPEAL OF SUNSET ON ELECTION.—Section 1400Z-2(a)(2) is amended to read as follows:

''(2) ELECTION.—No election may be made under paragraph (1) with respect to a sale or exchange if an election previously made with respect to such sale or exchange is in effect.''.

(2) MODIFICATION OF RULES FOR DEFERRAL OF GAIN.—Section 1400Z-2(b) is amended to read as follows:

''(b) DEFERRAL OF GAIN INVESTED IN OPPORTUNITY ZONE PROPERTY.—

''(1) YEAR OF INCLUSION.—Gain to which subsection (a)(1)(B) applies shall be included in gross income in the taxable year which includes the earlier of—

''(A) the date on which such investment is sold or exchanged, or

''(B) the date which is 5 years after the date the investment in the qualified opportunity fund was made.

''(2) AMOUNT INCLUDIBLE.—

''(A) IN GENERAL.—The amount of gain included in gross income under subsection (a)(1)(B) shall be the excess of—

''(i) the lesser of the amount of gain excluded under subsection (a)(1)(A) or the fair market value of the investment as determined as of the date described in paragraph (1), over

''(ii) the taxpayer's basis in the investment.

''(B) DETERMINATION OF BASIS.—

''(i) IN GENERAL.—Except as otherwise provided in this subparagraph or subsection (c), the taxpayer's basis in the investment shall be zero.

''(ii) INCREASE FOR GAIN RECOGNIZED UNDER SUBSECTION (a)(1)(B).—The basis in the investment shall be increased by the amount of gain recognized by reason of subsection (a)(1)(B) with respect to such investment.

''(iii) INVESTMENTS HELD FOR 5 YEARS.—

''(I) IN GENERAL.—In the case of any investment held for at least 5 years, the basis of such investment shall be increased by an amount equal to 10 percent (30 percent in the case of any investment in a qualified rural opportunity fund) of the amount of gain deferred by reason of subsection (a)(1)(A).

''(II) APPLICATION OF INCREASE.—For purposes of this subsection, any increase in basis under this clause shall be treated as occurring before the date described in paragraph (1)(B).

''(C) QUALIFIED RURAL OPPORTUNITY FUND.—For purposes of subparagraph (B)(iii)—

"(i) QUALIFIED RURAL OPPORTUNITY FUND.—The term 'qualified rural opportunity fund' means a qualified opportunity fund that holds at least 90 percent of its assets in qualified opportunity zone property which—

"(I) is qualified opportunity zone business property substantially all of the use of which, during substantially all of the fund's holding period for such property, was in a qualified opportunity zone comprised entirely of a rural area, or

"(II) is qualified opportunity zone stock, or a qualified opportunity zone partnership interest, in a qualified opportunity zone business in which substantially all of the tangible property owned or leased is qualified opportunity zone business property described in subsection (d)(3)(A)(i) and substantially all the use of which is in a qualified opportunity zone comprised entirely of a rural area.

For purposes of the preceding sentence, property held in the fund shall be measured under rules similar to the rules of subsection (d)(1).

"(ii) RURAL AREA.—The term 'rural area' means any area other than—

"(I) a city or town that has a population of greater than 50,000 inhabitants, and

"(II) any urbanized area contiguous and adjacent to a city or town described in subclause (I).".

(3) SPECIAL RULE FOR INVESTMENTS HELD AT LEAST 10 YEARS.—Section 1400Z-2(c) is amended by striking "makes an election under this clause" and all that follows and inserting "makes an election under this subsection, the basis of such investment shall be equal to—

"(A) in the case of an investment sold before the date that is 30 years after the date of the investment, the fair market value of such investment on the date such investment is sold or exchanged, or

"(B) in any other case, the fair market value of such investment on the date that is 30 years after the date of the investment.".

(4) DETERMINATION OF QUALIFIED OPPORTUNITY ZONE PROPERTY.—

(A) QUALIFIED OPPORTUNITY ZONE BUSINESS PROPERTY.—Section 1400Z-2(d)(2)(D)(i)(I) is amended by striking "December 31, 2017" and inserting "the applicable start date (as defined in section 1400Z-1(e)(2)) with respect to the qualified opportunity zone described in subclause (III)".

(B) QUALIFIED OPPORTUNITY ZONE STOCK AND PARTNERSHIP INTERESTS.—Section 1400Z-2(d)(2) is amended—

(i) by striking "December 31, 2017," each place it appears in subparagraphs (B)(i)(I) and (C)(i) and inserting "the applicable date", and

(ii) by adding at the end the following new subparagraph:

"(E) APPLICABLE DATE.—For purposes of this subparagraph, the term 'applicable date' means, with respect to any corporation or partnership which is a qualified opportunity zone business, the earliest date described in subparagraph (D)(i)(I) with respect to the qualified opportunity zone business property held by such qualified opportunity zone business.".

(C) SPECIAL RULE FOR IMPROVEMENT OF EXISTING STRUCTURES IN RURAL AREAS.—Section 1400Z–2(d)(2)(D)(ii) is amended by inserting "(50 percent of such adjusted basis in the case of property in a qualified opportunity zone comprised entirely of a rural area (as defined in subsection (b)(2)(C)(ii))" after "the adjusted basis of such property".

(5) EFFECTIVE DATES.—

(A) IN GENERAL.—Except as otherwise provided in this paragraph, the amendments made by this subsection shall apply to amounts invested in qualified opportunity funds after December 31, 2026.

(B) ACQUISITION OF QUALIFIED OPPORTUNITY ZONE PROPERTY.—The amendments made by subparagraphs (A) and (B) of paragraph (4) shall apply to property acquired after December 31, 2026.

(C) SUBSTANTIAL IMPROVEMENT.—The amendment made by paragraph (4)(C) shall take effect on the date of the enactment of this Act.

(d) INFORMATION REPORTING ON QUALIFIED OPPORTUNITY FUNDS AND QUALIFIED RURAL OPPORTUNITY FUNDS.—

(1) FILING REQUIREMENTS FOR FUNDS AND INVESTORS.— Subpart A of part III of subchapter A of chapter 61 is amended by inserting after section 6039J the following new sections:

"SEC. 6039K. RETURNS WITH RESPECT TO QUALIFIED OPPORTUNITY FUNDS AND QUALIFIED RURAL OPPORTUNITY FUNDS.

"(a) IN GENERAL.—Every qualified opportunity fund shall file an annual return (at such time and in such manner as the Secretary may prescribe) containing the information described in subsection (b).

"(b) INFORMATION FROM QUALIFIED OPPORTUNITY FUNDS.—The information described in this subsection is—

"(1) the name, address, and taxpayer identification number of the qualified opportunity fund,

"(2) whether the qualified opportunity fund is organized as a corporation or a partnership,

"(3) the value of the total assets held by the qualified opportunity fund as of each date described in section 1400Z–2(d)(1),

"(4) the value of all qualified opportunity zone property held by the qualified opportunity fund on each such date,

"(5) with respect to each investment held by the qualified opportunity fund in qualified opportunity zone stock or a qualified opportunity zone partnership interest—

"(A) the name, address, and taxpayer identification number of the corporation in which such stock is held or the partnership in which such interest is held, as the case may be,

"(B) each North American Industry Classification System (NAICS) code that applies to the trades or businesses conducted by such corporation or partnership, "(C) the population census tract or population census tracts in which the qualified opportunity zone business property of such corporation or partnership is located,

"(D) the amount of the investment in such stock or partnership interest as of each date described in section 1400Z–2(d)(1),

"(E) the value of tangible property held by such corporation or partnership on each such date which is owned by such corporation or partnership,

"(F) the value of tangible property held by such corporation or partnership on each such date which is leased by such corporation or partnership,

"(G) the approximate number of residential units (if any) for any real property held by such corporation or partnership, and

"(H) the approximate average monthly number of full-time equivalent employees of such corporation or partnership for the year (within numerical ranges identified by the Secretary) or such other indication of the employment impact of such corporation or partnership as determined appropriate by the Secretary,

"(6) with respect to the items of qualified opportunity zone business property held by the qualified opportunity fund—

"(A) the North American Industry Classification System (NAICS) code that applies to the trades or businesses in which such property is held,

"(B) the population census tract in which the property is located,

"(C) whether the property is owned or leased,

"(D) the aggregate value of the items of qualified opportunity zone property held by the qualified opportunity fund as of each date described in section 1400Z–2(d)(1), and

"(E) in the case of real property, the number of residential units (if any),

"(7) the approximate average monthly number of full-time equivalent employees for the year of the trades or businesses of the qualified opportunity fund in which qualified opportunity zone business property is held (within numerical ranges identified by the Secretary) or such other indication of the employment impact of such trades or businesses as determined appropriate by the Secretary,

"(8) with respect to each person who disposed of an investment in the qualified opportunity fund during the year—

"(A) the name, address, and taxpayer identification number of such person,

"(B) the date or dates on which the investment disposed was acquired, and

"(C) the date or dates on which any such investment was disposed and the amount of the investment disposed, and

"(9) such other information as the Secretary may require.

"(c) STATEMENT REQUIRED TO BE FURNISHED TO INVESTORS.—Every person required to make a return under subsection (a) shall furnish to each person whose name is required to be set forth in such return by reason of subsection (b)(8) (at such time and in such manner as the Secretary may prescribe) a written statement showing—

"(1) the name, address, and phone number of the information contact of the person required to make such return, and

"(2) the information required to be shown on such return by reason of subsection (b)(8) with respect to the person whose name is required to be so set forth.

"(d) DEFINITIONS.—For purposes of this section—

"(1) IN GENERAL.—Any term used in this section which is also used in subchapter Z of chapter 1 shall have the meaning given such term under such subchapter.

"(2) FULL-TIME EQUIVALENT EMPLOYEES.—The term 'full-time equivalent employees' means, with respect to any month, the sum of—

"(A) the number of full-time employees (as defined in section 4980H(c)(4)) for the month, plus

"(B) the number of employees determined (under rules similar to the rules of section 4980H(c)(2)(E)) by dividing the aggregate number of hours of service of employees who are not full-time employees for the month by 120.

"(e) APPLICATION TO QUALIFIED RURAL OPPORTUNITY FUNDS.—Every qualified rural opportunity fund (as defined in section 1400Z–2(b)(2)(C)) shall file the annual return required under subsection (a), and the statements required under subsection (c), applied—

"(1) by substituting 'qualified rural opportunity' for 'qualified opportunity' each place it appears,

"(2) by substituting 'section 1400Z–2(b)(2)(C)' for 'section 1400Z–2(d)(1)' each place it appears, and

"(3) by treating any reference (after the application of paragraph (1)) to qualified rural opportunity zone stock, a qualified rural opportunity zone partnership interest, a qualified rural opportunity zone business, or qualified opportunity zone business property as stock, an interest, a business, or property, respectively, described in subclause (I) or (II), as the case may be, of section 1400Z–2(b)(2)(C)(i).

"SEC. 6039L. INFORMATION REQUIRED FROM QUALIFIED OPPORTUNITY ZONE BUSINESSES AND QUALIFIED RURAL OPPORTUNITY ZONE BUSINESSES.

"(a) IN GENERAL.—Every applicable qualified opportunity zone business shall furnish to the qualified opportunity fund described in subsection (b) a written statement at such time, in such manner, and setting forth such information as the Secretary may by regulations prescribe for purposes of enabling such qualified opportunity fund to meet the requirements of section 6039K(b)(5).

"(b) APPLICABLE QUALIFIED OPPORTUNITY ZONE BUSINESS.—For purposes of subsection (a), the term 'applicable qualified opportunity zone business' means any qualified opportunity zone business—

"(1) which is a trade or business of a qualified opportunity fund,

"(2) in which a qualified opportunity fund holds qualified opportunity zone stock, or

"(3) in which a qualified opportunity fund holds a qualified opportunity zone partnership interest.

"(c) OTHER TERMS.—Any term used in this section which is also used in subchapter Z of chapter 1 shall have the meaning given such term under such subchapter.

"(d) APPLICATION TO QUALIFIED RURAL OPPORTUNITY BUSINESSES.—Every applicable qualified rural opportunity zone business (as defined in subsection (b) determined after application of the substitutions described in this sentence) shall furnish the written statement required under subsection (a), applied—

"(1) by substituting 'qualified rural opportunity' for 'qualified opportunity' each place it appears, and

"(2) by treating any reference (after the application of paragraph (1)) to qualified rural opportunity zone stock, a qualified rural opportunity zone partnership interest, or a qualified rural opportunity zone business as stock, an interest, or a business, respectively, described in subclause (I) or (II), as the case may be, of section 1400Z–2(b)(2)(C)(i).".

(2) PENALTIES.—

(A) IN GENERAL.—Part II of subchapter B of chapter 68 is amended by inserting after section 6725 the following new section:

"SEC. 6726. FAILURE TO COMPLY WITH INFORMATION REPORTING REQUIREMENTS RELATING TO QUALIFIED OPPORTUNITY FUNDS AND QUALIFIED RURAL OPPORTUNITY FUNDS.

"(a) IN GENERAL.—If any person required to file a return under section 6039K fails to file a complete and correct return under such section in the time and in the manner prescribed therefor, such person shall pay a penalty of $500 for each day during which such failure continues.

"(b) LIMITATION.—

"(1) IN GENERAL.—The maximum penalty under this section on failures with respect to any 1 return shall not exceed $10,000.

"(2) LARGE QUALIFIED OPPORTUNITY FUNDS.—In the case of any failure described in subsection (a) with respect to a fund the gross assets of which (determined on the last day of the taxable year) are in excess of $10,000,000, paragraph (1) shall be applied by substituting '$50,000' for '$10,000'.

"(c) PENALTY IN CASES OF INTENTIONAL DISREGARD.—If a failure described in subsection (a) is due to intentional disregard, then—

"(1) subsection (a) shall be applied by substituting '$2,500' for '$500',

"(2) subsection (b)(1) shall be applied by substituting '$50,000' for '$10,000', and

"(3) subsection (b)(2) shall be applied by substituting '$250,000' for '$50,000'.

"(d) INFLATION ADJUSTMENT.—

"(1) IN GENERAL.—In the case of any failure relating to a return required to be filed in a calendar year beginning after 2025, each of the dollar amounts in subsections (a), (b), and (c) shall be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year determined by substituting 'calendar year 2024' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

"(2) ROUNDING.—

"(A) IN GENERAL.—If the $500 dollar amount in subsection (a) and (c)(1) or the $2,500 amount in subsection (c)(1), after being increased under paragraph (1), is not a multiple of $10, such dollar amount shall be rounded to the next lowest multiple of $10.

"(B) ASSET THRESHOLD.—If the $10,000,000 dollar amount in subsection (b)(2), after being increased under paragraph (1), is not a multiple of $10,000, such dollar amount shall be rounded to the next lowest multiple of $10,000.

"(C) OTHER DOLLAR AMOUNTS.—If any dollar amount in subsection (b) or (c) (other than any amount to which subparagraph (A) or (B) applies), after being increased under paragraph (1), is not a multiple of $1,000, such dollar amount shall be rounded to the next lowest multiple of $1,000.".

(B) INFORMATION REQUIRED TO BE SENT TO OTHER TAXPAYERS.—Section 6724(d)(2), as amended by the preceding provisions of this Act, is amended—

(i) by striking "or" at the end of subparagraph (LL),

(ii) by striking the period at the end of subparagraph (MM) and inserting a comma, and

(iii) by inserting after subparagraph (MM) the following new subparagraphs:

"(NN) section 6039K(c) (relating to disposition of qualified opportunity fund investments), or

"(OO) section 6039L (relating to information required from certain qualified opportunity zone businesses and qualified rural opportunity zone businesses).".

(3) ELECTRONIC FILING.—Section 6011(e) is amended by adding at the end the following new paragraph:

"(8) QUALIFIED OPPORTUNITY FUNDS AND QUALIFIED RURAL OPPORTUNITY FUNDS.—Notwithstanding paragraphs (1) and (2), any return filed by a qualified opportunity fund or qualified rural opportunity fund under section 6039K shall be filed on magnetic media or other machine-readable form.".

(4) CLERICAL AMENDMENTS.—

(A) The table of sections for subpart A of part III of subchapter A of chapter 61 is amended by inserting after the item relating to section 6039J the following new items:

"Sec. 6039K. Returns with respect to qualified opportunity funds and qualified rural opportunity funds.
"Sec. 6039L. Information required from qualified opportunity zone businesses and qualified rural opportunity zone businesses.".

(B) The table of sections for part II of subchapter B of chapter 68 is amended by inserting after the item relating to section 6725 the following new item:

"Sec. 6726. Failure to comply with information reporting requirements relating to qualified opportunity funds and qualified rural opportunity funds.".

(5) EFFECTIVE DATE.—The amendments made by this subsection shall apply to taxable years beginning after the date of the enactment of this Act.

(e) SECRETARY REPORTING OF DATA ON OPPORTUNITY ZONE AND RURAL OPPORTUNITY ZONE TAX INCENTIVES.—

(1) IN GENERAL.—In addition to amounts otherwise available, there is appropriated, out of any money in the Treasury not otherwise appropriated, $15,000,000, to remain available until September 30, 2028, for necessary expenses of the Internal

Revenue Service to make the reports described in paragraph (2).

(2) REPORTS.—As soon as practical after the date of the enactment of this Act, and annually thereafter, the Secretary of the Treasury, or the Secretary's delegate (referred to in this section as the "Secretary") shall make publicly available a report on qualified opportunity funds.

(3) INFORMATION INCLUDED.—The report required under paragraph (2) shall include, to the extent available, the following information:

(A) The number of qualified opportunity funds.

(B) The aggregate dollar amount of assets held in qualified opportunity funds.

(C) The aggregate dollar amount of investments made by qualified opportunity funds in qualified opportunity fund property, stated separately for each North American Industry Classification System (NAICS) code.

(D) The percentage of population census tracts designated as qualified opportunity zones that have received qualified opportunity fund investments.

(E) For each population census tract designated as a qualified opportunity zone, the approximate average monthly number of full-time equivalent employees of the qualified opportunity zone businesses in such qualified opportunity zone for the preceding 12-month period (within numerical ranges identified by the Secretary) or such other indication of the employment impact of such qualified opportunity fund businesses as determined appropriate by the Secretary.

(F) The percentage of the total amount of investments made by qualified opportunity funds in—

(i) qualified opportunity zone property which is real property; and

(ii) other qualified opportunity zone property.

(G) For each population census tract, the aggregate approximate number of residential units resulting from investments made by qualified opportunity funds in real property.

(H) The aggregate dollar amount of investments made by qualified opportunity funds in each population census tract.

(4) ADDITIONAL INFORMATION.—

(A) IN GENERAL.—Beginning with the report submitted under paragraph (2) for the 6th year after the date of the enactment of this Act, the Secretary shall include in such report the impacts and outcomes of a designation of a population census tract as a qualified opportunity zone as measured by economic indicators, such as job creation, poverty reduction, new business starts, and other metrics as determined by the Secretary.

(B) SEMI-DECENNIAL INFORMATION.—

(i) IN GENERAL.—In the case of any report submitted under paragraph (2) in the 6th year or the 11th year after the date of the enactment of this Act, the Secretary shall include the following information:

(I) For population census tracts designated as a qualified opportunity zone, a comparison (based on aggregate information) of the factors listed in clause (iii) between the 5-year period ending on the date of the enactment of Public Law 115–97 and the most recent 5-year period for which data is available.

(II) For population census tracts designated as a qualified opportunity zone, a comparison (based on aggregate information) of the factors listed in clause (iii) for the most recent 5-year period for which data is available between such population census tracts and similar population census tracts that were not designated as a qualified opportunity zone.

(ii) CONTROL GROUPS.—For purposes of clause (i), the Secretary may combine population census tracts into such groups as the Secretary determines appropriate for purposes of making comparisons.

(iii) FACTORS LISTED.—The factors listed in this clause are the following:

(I) The unemployment rate.

(II) The number of persons working in the population census tract, including the percentage of such persons who were not residents in the population census tract in the preceding year.

(III) Individual, family, and household poverty rates.

(IV) Median family income of residents of the population census tract.

(V) Demographic information on residents of the population census tract, including age, income, education, race, and employment.

(VI) The average percentage of income of residents of the population census tract spent on rent annually.

(VII) The number of residences in the population census tract.

(VIII) The rate of home ownership in the population census tract.

(IX) The average value of residential property in the population census tract.

(X) The number of affordable housing units in the population census tract.

(XI) The number of new business starts in the population census tract.

(XII) The distribution of employees in the population census tract by North American Industry Classification System (NAICS) code.

(5) PROTECTION OF IDENTIFIABLE RETURN INFORMATION.—In making reports required under this subsection, the Secretary—

(A) shall establish appropriate procedures to ensure that any amounts reported do not disclose taxpayer return information that can be associated with any particular taxpayer or competitive or proprietary information, and

(B) if necessary to protect taxpayer return information, may combine information required with respect to individual population census tracts into larger geographic areas.

(6) DEFINITIONS.—Any term used in this subsection which is also used in subchapter Z of chapter 1 of the Internal Revenue Code of 1986 shall have the meaning given such term under such subchapter.

(7) REPORTS ON QUALIFIED RURAL OPPORTUNITY FUNDS.—The Secretary shall make publicly available, with respect to qualified rural opportunity funds, separate reports as required under this subsection, applied—

(A) by substituting "qualified rural opportunity" for "qualified opportunity" each place it appears,

(B) by substituting a reference to this Act for "Public Law 115–97", and

(C) by treating any reference (after the application of subparagraph (A)) to qualified rural opportunity zone stock, qualified rural opportunity zone partnership interest, qualified rural opportunity zone business, or qualified opportunity zone business property as stock, interest, business, or property, respectively, described in subclause (I) or (II), as the case may be, of section 1400Z–2(b)(2)(C)(i) of the Internal Revenue Code of 1986.

SEC. 70422. PERMANENT ENHANCEMENT OF LOW-INCOME HOUSING TAX CREDIT.

(a) PERMANENT STATE HOUSING CREDIT CEILING INCREASE FOR LOW-INCOME HOUSING CREDIT.—

(1) IN GENERAL.—Section 42(h)(3)(I) is amended—

(A) by striking "2018, 2019, 2020, and 2021," and inserting "beginning after December 31, 2025,",

(B) by striking "1.125" and inserting "1.12", and

(C) by striking "2018, 2019, 2020, AND 2021" in the heading and inserting "CALENDAR YEARS AFTER 2025".

(2) EFFECTIVE DATE.—The amendments made by this subsection shall apply to calendar years beginning after December 31, 2025.

(b) TAX-EXEMPT BOND FINANCING REQUIREMENT.—

(1) IN GENERAL.—Section 42(h)(4) is amended by striking subparagraph (B) and inserting the following:

"(B) SPECIAL RULE WHERE MINIMUM PERCENT OF BUILDINGS IS FINANCED WITH TAX-EXEMPT BONDS SUBJECT TO VOLUME CAP.—For purposes of subparagraph (A), paragraph (1) shall not apply to any portion of the credit allowable under subsection (a) with respect to a building if—

"(i) 50 percent or more of the aggregate basis of such building and the land on which the building is located is financed by 1 or more obligations described in subparagraph (A), or

"(ii)(I) 25 percent or more of the aggregate basis of such building and the land on which the building is located is financed by 1 or more obligations described in subparagraph (A), and

"(II) 1 or more of such obligations—

"(aa) are part of an issue the issue date of which is after December 31, 2025, and "(bb) provide the financing for not less than 5 percent of the aggregate basis of such building and the land on which the building is located.".

(2) EFFECTIVE DATE.—

(A) IN GENERAL.—The amendment made by this subsection shall apply to buildings placed in service in taxable years beginning after December 31, 2025.

(B) REHABILITATION EXPENDITURES TREATED AS SEPARATE NEW BUILDING.—In the case of any building with respect to which any expenditures are treated as a separate new building under section 42(e) of the Internal Revenue Code of 1986, for purposes of subparagraph (A), both the existing building and the separate new building shall be treated as having been placed in service on the date such expenditures are treated as placed in service under section 42(e)(4) of such Code.

SEC. 70423. PERMANENT EXTENSION OF NEW MARKETS TAX CREDIT.

(a) IN GENERAL.—Section 45D(f)(1)(H) is amended by striking "for for each of calendar years 2020 through 2025" and inserting " for each calendar year after 2019".

(b) CARRYOVER OF UNUSED LIMITATION.—Section 45D(f)(3) is amended—

(1) by striking "If the" and inserting the following:

"(A) IN GENERAL.—If the", and

(2) by striking the second sentence and inserting the following:

"(B) LIMITATION.—No amount may be carried under subparagraph (A) to any calendar year afer the fifth calendar year after the calendar year in which the excess described in such subparagraph occurred. For purposes of this subparagraph, any excess described in subparagraph (A) with respect to any calendar year before 2026 shall be treated as occurring in calendar year 2025.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to calendar years beginning after December 31, 2025.

SEC. 70424. PERMANENT AND EXPANDED REINSTATEMENT OF PARTIAL DEDUCTION FOR CHARITABLE CONTRIBUTIONS OF INDIVIDUALS WHO DO NOT ELECT TO ITEMIZE.

(a) IN GENERAL.—Section 170(p) is amended—

(1) by striking "$300 ($600" and inserting "$1,000 ($2,000", and

(2) by striking "beginning in 2021".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70425. 0.5 PERCENT FLOOR ON DEDUCTION OF CONTRIBUTIONS MADE BY INDIVIDUALS.

(a) IN GENERAL.—

(1) IN GENERAL.—Paragraph (1) of section 170(b) is amended by adding at the end the following new subparagraph:

"(I) 0.5-PERCENT FLOOR.—Any charitable contribution otherwise allowable (without regard to this subparagraph) as a deduction under this section shall be allowed only to the extent that the aggregate of such contributions exceeds 0.5 percent of the taxpayer's contribution base for the taxable year. The preceding sentence shall be applied—

"(i) first, by taking into account charitable contributions to which subparagraph (D) applies to the extent thereof,

"(ii) second, by taking into account charitable contributions to which subparagraph (C) applies to the extent thereof,

"(iii) third, by taking into account charitable contributions to which subparagraph (B) applies to the extent thereof,

"(iv) fourth, by taking into account charitable contributions to which subparagraph (E) applies to the extent thereof,

"(v) fifth, by taking into account charitable contributions to which subparagraph (A) applies to the extent thereof, and

"(vi) sixth, by taking into account charitable contributions to which subparagraph (G) applies to the extent thereof.".

(2) APPLICATION OF CARRYFORWARD.—Paragraph (1) of section 170(d) is amended by adding at the end the following new subparagraph:

"(C) CONTRIBUTIONS DISALLOWED BY 0.5-PERCENT FLOOR CARRIED FORWARD ONLY FROM YEARS IN WHICH LIMITATION IS EXCEEDED.—

"(i) IN GENERAL.—In the case of any taxable year from which an excess is carried forward (determined without regard to this subparagraph) under any carryover rule, the applicable carryover rule shall be applied by increasing the excess determined under such applicable carryover rule for the contribution year (before the application of subparagraph (B)) by the amount attributable to the charitable contributions to which such rule applies which is not allowed as a deduction for the contribution year by reason of subsection (b)(1)(I).

"(ii) CARRYOVER RULE.—For purposes of this subparagraph, the term 'carryover rule' means—

"(I) subparagraph (A) of this paragraph,

"(II) subparagraphs (C)(ii), (D)(ii), (E)(ii), and (G)(ii) of subsection (b)(1), and

"(III) the second sentence of subsection (b)(1)(B).

"(iii) APPLICABLE CARRYOVER RULE.—For purposes of this subparagraph, the term 'applicable carryover rule' means any carryover rule applicable to charitable contributions which were (in whole or in part) not allowed as a deduction for the contribution year by reason of subsection (b)(1)(I).".

(3) COORDINATION WITH DEDUCTION FOR NONITEMIZERS.—Section 170(p), as amended by this Act, is further amended by inserting ", (b)(1)(I)," after "subsections (b)(1)(G)(ii)".

(b) MODIFICATION OF LIMITATION FOR CASH CONTRIBUTIONS.—

(1) IN GENERAL.—Clause (i) of section 170(b)(1)(G) is amended to read as follows:

"(i) IN GENERAL.—For taxable years beginning after December 31, 2017, any contribution of cash to an organization described in subparagraph (A) shall be allowed as a deduction under subsection (a) to the extent that the aggregate of such contributions does not exceed the excess of—

"(I) 60 percent of the taxpayer's contribution base for the taxable year, over

"(II) the aggregate amount of contributions taken into account under subparagraph (A) for such taxable year.".

(2) COORDINATION WITH OTHER LIMITATIONS.—

(A) IN GENERAL.—Clause (iii) of section 170(b)(1)(G) is amended—

(i) by striking "SUBPARAGRAPHS (A) AND (B)" in the heading and inserting "SUBPARAGRAPH (A)", and

(ii) in subclause (II), by striking ", and subparagraph (B)" and all that follows through "this subparagraph".

(B) OTHER CONTRIBUTIONS.—Subparagraph (B) of section 170(b)(1) is amended—

(i) by striking "to which subparagraph (A)" both places it appears and inserting "to which subparagraph (A) or (G)", and

(ii) in clause (ii), by striking "over the amount" and all that follows through "subparagraph (C))." and inserting "over—

"(I) the amount of charitable contributions allowable under subparagraph (A) (determined without regard to subparagraph (C)) and subparagraph (G), reduced by

"(II) so much of the contributions taken into account under subparagraph (G) as does not exceed 10 percent of the taxpayer's contribution base.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70426. 1-PERCENT FLOOR ON DEDUCTION OF CHARITABLE CONTRIBUTIONS MADE BY CORPORATIONS.

(a) IN GENERAL.—Section 170(b)(2)(A) is amended to read as follows:

"(A) IN GENERAL.—Any charitable contribution otherwise allowable (without regard to this subparagraph) as a deduction under this section for any taxable year, other than any contribution to which subparagraph (B) or (C) applies, shall be allowed only to the extent that the aggregate of such contributions—

"(i) exceeds 1 percent of the taxpayer's taxable income for the taxable year, and

"(ii) does not exceed 10 percent of the taxpayer's taxable income for the taxable year.".

(b) APPLICATION OF CARRYFORWARD.—Section 170(d)(2) is amended to read as follows:

"(2) CORPORATIONS.—

"(A) IN GENERAL.—Any charitable contribution taken into account under subsection (b)(2)(A) for any taxable year which is not allowed as a deduction by reason of clause (ii) thereof shall be taken into account as a charitable contribution for the succeeding taxable year, except that, for purposes of determining under this subparagraph whether such contribution is allowed in such succeeding taxable year, contributions in such succeeding taxable year (determined without regard to this paragraph) shall be taken into account under subsection (b)(2)(A) before any contribution taken into account by reason of this paragraph.

"(B) 5-YEAR CARRYFORWARD.—No charitable contribution may be carried forward under subparagraph (A) to any taxable year following the fifth taxable year after the taxable year in which the charitable contribution was first taken into account. For purposes of the preceding sentence, contributions shall be treated as allowed on a first-in first-out basis.

"(C) CONTRIBUTIONS DISALLOWED BY 1-PERCENT FLOOR CARRIED FORWARD ONLY FROM YEARS IN WHICH 10 PERCENT LIMITATION IS EXCEEDED.—In the case of any taxable year from which a charitable contribution is carried forward under subparagraph (A) (determined without regard this subparagraph), subparagraph (A) shall be applied by substituting 'clause (i) or (ii)' for 'clause (ii)'.

"(D) SPECIAL RULE FOR NET OPERATING LOSS CARRYOVERS.—The amount of charitable contributions carried forward under subparagraph (A) shall be reduced to the extent that such carryfoward would (but for this subparagraph) reduce taxable income (as computed for purposes of the second sentence of section 172(b)(2)) and increase a net operating loss carryover under section 172 to a succeeding taxable year.".

(c) CONFORMING AMENDMENTS.—Subparagraphs (B)(ii) and (C)(ii) of section 170(b)(2) are each amended by inserting "other than subparagraph (C) thereof" after "subsection (d)(2)".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70427. PERMANENT INCREASE IN LIMITATION ON COVER OVER OF TAX ON DISTILLED SPIRITS.

(a) IN GENERAL.—Paragraph (1) of section 7652(f) is amended to read as follows:

"(1) $13.25, or".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to distilled spirits brought into the United States after December 31, 2025.

SEC. 70428. NONPROFIT COMMUNITY DEVELOPMENT ACTIVITIES IN REMOTE NATIVE VILLAGES.

(a) IN GENERAL.—For purposes of subchapter F of chapter 1 of the Internal Revenue Code of 1986, any activity substantially related to participation or investment in fisheries in the Bering Sea and Aleutian Islands statistical and reporting areas (as described in Figure 1 of section 679 of title 50, Code of Federal Regulations) carried on by an entity identified in section 305(i)(1)(D) of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1855(i)(1)(D)) (as in effect on the date of enactment of this section) shall be considered substantially related to the exercise or performance of the purpose constituting the basis of such entity's exemption under section 501(a) of such Code if the conduct of such activity is in furtherance of 1 or more of the purposes specified in section 305(i)(1)(A) of such Act (as so in effect). For purposes of this paragraph, activities substantially related to participation or investment in fisheries include the harvesting, processing, transportation, sales, and marketing of fish and fish products of the Bering Sea and Aleutian Islands statistical and reporting areas.

(b) APPLICATION TO CERTAIN WHOLLY OWNED SUBSIDIARIES.—If the assets of a trade or business relating to an activity described in subsection (a) of any subsidiary wholly owned by an entity identified in section 305(i)(1)(D) of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1855(i)(1)(D)) (as in effect on the date of enactment of this section) are transferred to such entity (including in liquidation of such subsidiary) not later than 18 months after the date of the enactment of this Act—

(1) no gain or income resulting from such transfer shall be recognized to either such subsidiary or such entity under such Code, and

(2) all income derived from such subsidiary from such transferred trade or business shall be exempt from taxation under such Code.

(c) EFFECTIVE DATE.—This section shall take effect on the date of the enactment of this Act and shall remain effective during the existence of the western Alaska community development quota program established by Section 305(i)(1) of the Magnuson-Stevens Fishery Conservation and Management Act (16 U.S.C. 1855(i)(1)), as amended.

SEC. 70429. ADJUSTMENT OF CHARITABLE DEDUCTION FOR CERTAIN EXPENSES INCURRED IN SUPPORT OF NATIVE ALASKAN SUBSISTENCE WHALING.

(a) IN GENERAL.—Section 170(n)(1) of the Internal Revenue Code of 1986 is amended by striking "$10,000" and inserting "$50,000".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70430. EXCEPTION TO PERCENTAGE OF COMPLETION METHOD OF ACCOUNTING FOR CERTAIN RESIDENTIAL CONSTRUCTION CONTRACTS.

(a) IN GENERAL.—Section 460(e) is amended—

(1) in paragraph (1)—

(A) by striking "home construction contract" both places it appears and inserting "residential construction contract", and

(B) by inserting "(determined by substituting '3-year' for '2-year' in subparagraph (B)(i) for any residential construction contract which is not a home construction contract)" after "the requirements of clauses (i) and (ii) of subparagraph (B)",

(2) by striking paragraph (4) and redesignating paragraph (5) as paragraph (4), and

(3) in subparagraph (A) of paragraph (4), as so redesignated, by striking "paragraph (4)" and inserting "paragraph (3)".

(b) APPLICATION OF EXCEPTION FOR PURPOSES OF ALTERNATIVE MINIMUM TAX.—Section 56(a)(3) is amended by striking "any home construction contract (as defined in section 460(e)(6))" and inserting "any residential construction contract (as defined in section 460(e)(4))".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to contracts entered into in taxable years beginning after the date of the enactment of this Act.

Subchapter D—Permanent Investments in Small Business and Rural America

SEC. 70431. EXPANSION OF QUALIFIED SMALL BUSINESS STOCK GAIN EXCLUSION.

(a) PHASED INCREASE IN EXCLUSION FOR GAIN FROM QUALIFIED SMALL BUSINESS STOCK.—

(1) IN GENERAL.—Section 1202(a)(1) is amended to read as follows:

"(1) IN GENERAL.— In the case of a taxpayer other than a corporation, gross income shall not include—

"(A) except as provided in paragraphs (3) and (4), 50 percent of any gain from the sale or exchange of qualified small business stock acquired on or before the applicable date and held for more than 5 years, and

"(B) the applicable percentage of any gain from the sale or exchange of qualified small business stock acquired after the applicable date and held for at least 3 years.".

(2) APPLICABLE PERCENTAGE.—Section 1202(a) is amended by adding at the end the following new paragraph:

"(5) APPLICABLE PERCENTAGE.—The applicable percentage under paragraph (1) shall be determined under the following table:

"Years stock held:	Applicable percentage:
3 years	50%
4 years	75%
5 years or more	100%".

(3) APPLICABLE DATE; ACQUISITION DATE.—Section 1202(a), as amended by paragraph (2), is amended by adding at the end the following new paragraph:

"(6) APPLICABLE DATE; ACQUISITION DATE.—For purposes of this section—

"(A) APPLICABLE DATE.—The term 'applicable date' means the date of the enactment of this paragraph.

"(B) ACQUISITION DATE.—In the case of any stock which would (but for this paragraph) be treated as having been acquired before, on, or after the applicable date, whichever is applicable, the acquisition date for purposes of this section shall be the first day on which such stock was held by the taxpayer determined after the application of section 1223.".

(4) CONTINUED TREATMENT AS NOT ITEM OF TAX PREFERENCE.—

(A) IN GENERAL.—Section 57(a)(7) is amended by striking "An amount" and inserting "In the case of stock acquired on or before the date of the enactment of the Creating Small Business Jobs Act of 2010, an amount".

(B) CONFORMING AMENDMENT.—Section 1202(a)(4) is amended—

(i) by striking ", and" at the end of subparagraph (B) and inserting a period, and

(ii) by striking subparagraph (C).

(5) OTHER CONFORMING AMENDMENTS.—

(A) Paragraphs (3)(A) and (4)(A) of section 1202(a) are each amended by striking "paragraph (1)" and inserting "paragraph (1)(A)".

(B) Paragraph (4)(A) of section 1202(a) is amended by inserting "and on or before the applicable date" after "2010".

(C) Sections 1202(b)(2), 1202(g)(2)(A), and 1202(j)(1)(A) are each amended by striking "more than 5 years" and inserting "at least 3 years (more than 5 years in the case of stock acquired on or before the applicable date)".

(6) EFFECTIVE DATES.—

(A) IN GENERAL.—Except as provided in subparagraph (B), the amendments made by this subsection shall apply to taxable years beginning after the date of the enactment of this Act.

(B) CONTINUED TREATMENT AS NOT ITEM OF TAX PREFERENCE.—The amendments made by paragraph (4) shall take effect as if included in the enactment of section 2011 of the Creating Small Business Jobs Act of 2010.

(b) INCREASE IN PER ISSUER LIMITATION.—

(1) IN GENERAL.—Subparagraph (A) of section 1202(b)(1) is amended to read as follows:

"(A) the applicable dollar limit for the taxable year, or".

(2) APPLICABLE DOLLAR LIMIT.—Section 1202 (b) is amended by adding at the end the following:

"(4) APPLICABLE DOLLAR LIMIT.—For purposes of paragraph (1)(A), the applicable dollar limit for any taxable year with respect to eligible gain from 1 or more dispositions by a taxpayer of qualified business stock of a corporation is—

"(A) if such stock was acquired by the taxpayer on or before the applicable date, $10,000,000, reduced by the aggregate amount of eligible gain taken into account by the taxpayer under subsection (a) for prior taxable years and attributable to dispositions of stock issued by such corporation and acquired by the taxpayer before, on, or after the applicable date, and

"(B) if such stock was acquired by the taxpayer after the applicable date, $15,000,000, reduced by the sum of—

"(i) the aggregate amount of eligible gain taken into account by the taxpayer under subsection (a) for prior taxable years and attributable to dispositions of stock issued by such corporation and acquired by the taxpayer before, on, or after the applicable date, plus

"(ii) the aggregate amount of eligible gain taken into account by the taxpayer under subsection (a) for the taxable year and attributable to dispositions of stock issued by such corporation and acquired by the taxpayer on or before the applicable date.

"(5) INFLATION ADJUSTMENT.—

"(A) IN GENERAL.—In the case of any taxable year beginning after 2026, the $15,000,000 amount in paragraph (4)(B) shall be increased by an amount equal to —

"(i) such dollar amount, multiplied by

"(ii) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

If any increase under this subparagraph is not a multiple of $10,000, such increase shall be rounded to the nearest multiple of $10,000.

"(B) NO INCREASE ONCE LIMIT REACHED.—If, for any taxable year, the eligible gain attributable to dispositions of stock issued by a corporation and acquired by the taxpayer after the applicable date exceeds the applicable dollar limit, then notwithstanding any increase under subparagraph (A) for any subsequent taxable year, the applicable dollar limit for such subsequent taxable year shall be zero.".

(3) SEPARATE RETURNS.—Subparagraph (A) of section 1202(b)(3) is amended to read as follows:

"(A) SEPARATE RETURNS.—In the case of a separate return by a married individual for any taxable year—

"(i) paragraph (4)(A) shall be applied by substituting '$5,000,000' for '$10,000,000', and

"(ii) paragraph (4)(B) shall be applied by substituting one-half of the dollar amount in effect under such paragraph for the taxable year for the amount so in effect.".

(4) EFFECTIVE DATE.—The amendments made by this subsection shall apply to taxable years beginning after the date of the enactment of this Act.

(c) INCREASE IN LIMIT IN AGGREGATE GROSS ASSETS.—

(1) IN GENERAL.—Subparagraphs (A) and (B) of section 1202(d)(1) are each amended by striking "$50,000,000" and inserting "$75,000,000".

(2) INFLATION ADJUSTMENT.—Section 1202(b) is amended by adding at the end the following:

"(4) INFLATION ADJUSTMENT.—In the case of any taxable year beginning after 2026, the $75,000,000 amounts in paragraphs (1)(A) and (1)(B) shall each be increased by an amount equal to—

"(A) such dollar amount, multiplied by

"(B) the cost-of-living adjustment determined under section 1(f)(3) for the calendar year in which the taxable year begins, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

If any increase under this paragraph is not a multiple of $10,000, such increase shall be rounded to the nearest multiple of $10,000.".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall apply to stock issued after the date of the enactment of this Act.

SEC. 70432. REPEAL OF REVISION TO DE MINIMIS RULES FOR THIRD PARTY NETWORK TRANSACTIONS.

(a) REINSTATEMENT OF EXCEPTION FOR DE MINIMIS PAYMENTS AS IN EFFECT PRIOR TO ENACTMENT OF AMERICAN RESCUE PLAN ACT OF 2021.—

(1) IN GENERAL.—Section 6050W(e) is amended to read as follows:

"(e) EXCEPTION FOR DE MINIMIS PAYMENTS BY THIRD PARTY SETTLEMENT ORGANIZATIONS.—A third party settlement organization shall be required to report any information under subsection (a) with respect to third party network transactions of any participating payee only if—

"(1) the amount which would otherwise be reported under subsection (a)(2) with respect to such transactions exceeds $20,000, and

"(2) the aggregate number of such transactions exceeds 200.".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall take effect as if included in section 9674 of the American Rescue Plan Act.

(b) APPLICATION OF DE MINIMIS RULE FOR THIRD PARTY NETWORK TRANSACTIONS TO BACKUP WITHHOLDING.—

(1) IN GENERAL.—Section 3406(b) is amended by adding at the end the following new paragraph:

"(8) OTHER REPORTABLE PAYMENTS INCLUDE PAYMENTS IN SETTLEMENT OF THIRD PARTY NETWORK TRANSACTIONS ONLY WHERE AGGREGATE TRANSACTIONS EXCEED REPORTING THRESHOLD FOR THE CALENDAR YEAR.—

"(A) IN GENERAL.—Any payment in settlement of a third party network transaction required to be shown on a return required under section 6050W which is made during any calendar year shall be treated as a reportable payment only if—

"(i) the aggregate number of transactions with respect to the participating payee during such calendar year exceeds the number of transactions specified in section 6050W(e)(2), and

"(ii) the aggregate amount of transactions with respect to the participating payee during such calendar year exceeds the dollar amount specified in section 6050W(e)(1) at the time of such payment.

"(B) EXCEPTION IF THIRD PARTY NETWORK TRANSACTIONS MADE IN PRIOR YEAR WERE REPORTABLE.—Subparagraph (A) shall not apply with respect to payments to any participating payee during any calendar year if one or more payments in settlement of third party network transactions made by the payor to the participating payee during the preceding calendar year were reportable payments.".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to calendar years beginning after December 31, 2024.

SEC. 70433. INCREASE IN THRESHOLD FOR REQUIRING INFORMATION REPORTING WITH RESPECT TO CERTAIN PAYEES.

(a) IN GENERAL.—Section 6041(a) is amended by striking "$600" and inserting "$2,000".

(b) INFLATION ADJUSTMENT.—Section 6041 is amended by adding at the end the following new subsection:

"(h) INFLATION ADJUSTMENT.—In the case of any calendar year after 2026, the dollar amount in subsection (a) shall be increased by an amount equal to—

"(1) such dollar amount, multiplied by

"(2) the cost-of-living adjustment determined under section 1(f)(3) for such calendar year, determined by substituting 'calendar year 2025' for 'calendar year 2016' in subparagraph (A)(ii) thereof.

If any increase under the preceding sentence is not a multiple of $100, such increase shall be rounded to the nearest multiple of $100.".

(c) APPLICATION TO REPORTING ON REMUNERATION FOR SERVICES.—Section 6041A(a)(2) is amended by striking "is $600 or more" and inserting "equals or exceeds the dollar amount in effect for such calendar year under section 6041(a)".

(d) APPLICATION TO BACKUP WITHHOLDING.—Section 3406(b)(6) is amended—

(1) by striking "$600" in subparagraph (A) and inserting "the dollar amount in effect for such calendar year under section 6041(a)", and

(2) by striking "ONLY WHERE AGGREGATE FOR CALENDAR YEAR IS $600 OR MORE" in the heading and inserting "ONLY WHERE IN EXCESS OF THRESHOLD".

(e) CONFORMING AMENDMENTS.—

(1) The heading of section 6041(a) is amended by striking "OF $600 OR MORE" and inserting "EXCEEDING THRESHOLD".

(2) Section 6041(a) is amended by striking "taxable year" and inserting "calendar year".

(f) EFFECTIVE DATE.—The amendments made by this section shall apply with respect to payments made after December 31, 2025.

SEC. 70434. TREATMENT OF CERTAIN QUALIFIED SOUND RECORDING PRODUCTIONS.

(a) ELECTION TO TREAT COSTS AS EXPENSES.—Section 181(a)(1) is amended by striking "qualified film or television production, and any qualified live theatrical production," and inserting "qualified film or television production, any qualified live theatrical production, and any qualified sound recording production".

(b) DOLLAR LIMITATION.—Section 181(a)(2) is amended by adding at the end the following new subparagraph:

"(C) QUALIFIED SOUND RECORDING PRODUCTION.—Paragraph (1) shall not apply to so much of the aggregate cost of any qualified sound recording production, or to so much of the aggregate, cumulative cost of all such qualified sound recording productions in the taxable year, as exceeds $150,000.".

(c) NO OTHER DEDUCTION OR AMORTIZATION DEDUCTION ALLOWABLE.—Section 181(b) is amended by striking "qualified film or television production or any qualified live theatrical production" and inserting "qualified film or television production, any qualified live theatrical production, or any qualified sound recording production".

(d) ELECTION.—Section 181(c)(1) is amended by striking "qualified film or television production or any qualified live theatrical production" and inserting "qualified film or television production, any qualified live theatrical production, or any qualified sound recording production".

(e) QUALIFIED SOUND RECORDING PRODUCTION DEFINED.—Section 181 is amended by redesignating subsections (f) and (g) as subsections (g) and (h), respectively, and by inserting after subsection (e) the following new subsection:

"(f) QUALIFIED SOUND RECORDING PRODUCTION.—For purposes of this section, the term 'qualified sound recording production' means a sound recording (as defined in section 101 of title 17, United States Code) produced and recorded in the United States.".

(f) APPLICATION OF TERMINATION.—Section 181(h), as redesignated by subsection (e), is amended by striking "qualified film and television productions or qualified live theatrical productions" and inserting "qualified film and television productions, qualified live theatrical productions, or qualified sound recording productions".

(g) BONUS DEPRECIATION.—

(1) QUALIFIED SOUND RECORDING PRODUCTION AS QUALIFIED PROPERTY.—Section 168(k)(2)(A)(i) is amended—

(A) by striking "or" at the end of subclause (IV), by inserting "or" at the end of subclause (V), and by inserting after subclause (V) the following:

"(VI) which is a qualified sound recording production (as defined in subsection (f) of section 181) for which a deduction would have been allowable under section 181 without regard to subsections (a)(2) and (h) of such section or this subsection, and", and

(B) in subclauses (IV) and (V) (as so amended) by striking "without regard to subsections (a)(2) and (g)" both places it appears and inserting "without regard to subsections (a)(2) and (h)".

(2) PRODUCTION PLACED IN SERVICE.—Section 168(k)(2)(H) is amended by striking "and" at the end of clause (i), by striking the period at the end of clause (ii) and inserting ", and", and by adding after clause (ii) the following:

"(iii) a qualified sound recording production shall be considered to be placed in service at the time of initial release or broadcast.".

(h) CONFORMING AMENDMENTS.—

(1) The heading for section 181 is amended to read as follows: "**TREATMENT OF CERTAIN QUALIFIED PRODUCTIONS.**".

(2) The table of sections for part VI of subchapter B of chapter 1 is amended by striking the item relating to section 181 and inserting the following new item:

(i) EFFECTIVE DATE.—The amendments made by this section shall apply to productions commencing in taxable years ending after the date of the enactment of this Act.

SEC. 70435. EXCLUSION OF INTEREST ON LOANS SECURED BY RURAL OR AGRICULTURAL REAL PROPERTY.

(a) IN GENERAL.—Part III of subchapter B of chapter 1, as amended by the preceding provisions of this Act, is amended by inserting after section 139K the following new section:

"SEC. 139L. INTEREST ON LOANS SECURED BY RURAL OR AGRICULTURAL REAL PROPERTY.

"(a) IN GENERAL.—Gross income shall not include 25 percent of the interest received by a qualified lender on any qualified real estate loan.

"(b) QUALIFIED LENDER.—For purposes of this section, the term 'qualified lender' means—

"(1) any bank or savings association the deposits of which are insured under the Federal Deposit Insurance Act (12 U.S.C. 1811 et seq.),

"(2) any State- or federally-regulated insurance company,

"(3) any entity wholly owned, directly or indirectly, by a company that is treated as a bank holding company for purposes of section 8 of the International Banking Act of 1978 (12 U.S.C. 3106) if—

"(A) such entity is organized, incorporated, or established under the laws of the United States or any State, and

"(B) the principal place of business of such entity is in the United States (including any territory of the United States),

"(4) any entity wholly owned, directly or indirectly, by a company that is considered an insurance holding company under the laws of any State if such entity satisfies the requirements described in subparagraphs (A) and (B) of paragraph (3), and

"(5) with respect to interest received on a qualified real estate loan secured by real estate described in subsection (c)(3)(A), any federally chartered instrumentality of the United States established under section 8.1(a) of the Farm Credit Act of 1971 (12 U.S.C. 2279aa-1(a)).

"(c) QUALIFIED REAL ESTATE LOAN.—For purposes of this section—

"(1) IN GENERAL.—The term 'qualified real estate loan' means any loan—

"(A) secured by—

"(i) rural or agricultural real estate, or

"(ii) a leasehold mortgage (with a status as a lien) on rural or agricultural real estate,

"(B) made to a person other than a specified foreign entity (as defined in section 7701(a)(51)), and

"(C) made after the date of the enactment of this section.

For purposes of the preceding sentence, the determination of whether property securing such loan is rural or agricultural real estate shall be made as of the time the interest income on such loan is accrued.

"(2) REFINANCINGS.—For purposes of subparagraphs (A) and (C) of paragraph (1), a loan shall not be treated as made after the date of the enactment of this section to the extent that the proceeds of such loan are used to refinance a loan which was made on or before the date of the enactment of this section (or, in the case of any series of refinancings, the original loan was made on or before such date).

"(3) RURAL OR AGRICULTURAL REAL ESTATE.—The term 'rural or agricultural real estate' means—

"(A) any real property which is substantially used for the production of one or more agricultural products,

"(B) any real property which is substantially used in the trade or business of fishing or seafood processing, and

"(C) any aquaculture facility.

Such term shall not include any property which is not located in a State or a possession of the United States.

"(4) AQUACULTURE FACILITY.—The term 'aquaculture facility' means any land, structure, or other appurtenance that is used for aquaculture (including any hatchery, rearing pond, raceway, pen, or incubator).

"(d) COORDINATION WITH SECTION 265.—In the case of any qualified real estate loan, section 265 shall be applied—

"(1) by treating any qualified real estate loan for purposes of subsection (a)(2) thereof as an obligation the interest on which is wholly exempt from the taxes imposed by this subtitle,

"(2) by substituting '25 percent of the interest on indebtedness' for 'Interest on indebtedness' in such subsection (a)(2),

"(3) by treating 25 percent of the adjusted basis of any qualified real estate loan as adjusted basis of a tax-exempt obligation described in subsection (b)(4)(B) thereof, and

"(4) by substituting '25 percent of the amount of such indebtedness' for 'the amount of such indebtedness' in subsection (b)(6)(A)(a)(ii) thereof.".

(b) CLERICAL AMENDMENT.—The table of sections for part III of subchapter B of chapter 1, as amended by the preceding provisions of this Act, is amended by inserting after the item relating to section 139K the following new item:

"Sec. 139L. Interest on loans secured by rural or agricultural real property.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years ending after the date of the enactment of this Act.

SEC. 70436. REDUCTION OF TRANSFER AND MANUFACTURING TAXES FOR CERTAIN DEVICES.

(a) TRANSFER TAX.—Section 5811(a) is amended to read as follows:

"(a) RATE.—There shall be levied, collected, and paid on firearms transferred a tax at the rate of—

"(1) $200 for each firearm transferred in the case of a machinegun or a destructive device, and

"(2) $0 for any firearm transferred which is not described in paragraph (1).".

(b) MAKING TAX.—Section 5821(a) is amended to read as follows:

"(a) RATE.—There shall be levied, collected, and paid upon the making of a firearm a tax at the rate of—

"(1) $200 for each firearm made in the case of a machinegun or a destructive device, and

"(2) $0 for any firearm made which is not described in paragraph (1).".

(c) CONFORMING AMENDMENT.—Section 4182(a) is amended by adding at the end the following: "For purposes of the preceding sentence, any firearm described in section 5811(a)(2) shall be deemed to be a firearm on which the tax provided by section 5811 has been paid."

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to calendar quarters beginning more than 90 days after the date of the enactment of this Act.

SEC. 70437. TREATMENT OF CAPITAL GAINS FROM THE SALE OF CERTAIN FARMLAND PROPERTY.

(a) IN GENERAL.—Part IV of subchapter O of chapter 1 is amended by redesignating section 1062 as section 1063 and by inserting after section 1061 the following new section:

"SEC. 1062. GAIN FROM THE SALE OR EXCHANGE OF QUALIFIED FARMLAND PROPERTY TO QUALIFIED FARMERS.

"(a) ELECTION TO PAY TAX IN INSTALLMENTS.—In the case of gain from the sale or exchange of qualified farmland property to a qualified farmer, at the election of the taxpayer, the portion of the net income tax of such taxpayer for the taxable year of the sale or exchange which is equal to the applicable net tax liability shall be paid in 4 equal installments.

"(b) RULES RELATING TO INSTALLMENT PAYMENTS.—

"(1) DATE FOR PAYMENT OF INSTALLMENTS.—If an election is made under subsection (a), the first installment shall be paid on the due date (determined without regard to any extension of time for filing the return) for the return of tax for the taxable year in which the sale or exchange occurs and each succeeding installment shall be paid on the due date (as so determined) for the return of tax for the taxable year following the taxable year with respect to which the preceding installment was made.

"(2) ACCELERATION OF PAYMENT.—

"(A) IN GENERAL.—If there is an addition to tax for failure to timely pay any installment required under this section, then the unpaid portion of all remaining installments shall be due on the date of such failure.

"(B) INDIVIDUALS.—In the case of an individual, if the individual dies, then the unpaid portion of all remaining installment shall be paid on the due date for the return of tax for the taxable year in which the taxpayer dies.

"(C) C CORPORATIONS.—In the case of a taxpayer which is a C corporation, trust, or estate, if there is a liquidation or sale of substantially all the assets of the taxpayer (including in a title 11 or similar case), a cessation of business by the taxpayer (in the case of a C corporation), or any similar circumstance, then the unpaid portion of all remaining installments shall be due on the date of such event (or in the case of a title 11 or similar case, the day before the petition is filed). The preceding sentence shall not apply to the sale of substantially all the assets of a taxpayer to a buyer if such buyer enters into an agreement with the Secretary under which such buyer is liable for the remaining installments due under this subsection in the same manner as if such buyer were the taxpayer.

"(3) PRORATION OF DEFICIENCY TO INSTALLMENTS.—If an election is made under subsection (a) to pay the applicable net tax liability in installments and a deficiency has been assessed with respect to such applicable net tax liability, the deficiency shall be prorated to the installments payable under subsection (a). The part of the deficiency so prorated to any installment the date for payment of which has not arrived shall be collected at the same time as, and as a part of, such installment. The part of the deficiency so prorated to any installment the date for payment of which has arrived shall be paid upon notice and demand from the Secretary. This section shall not apply if the deficiency is due to negligence, to intentional disregard of rules and regulations, or to fraud with intent to evade tax.

"(c) ELECTION.—

"(1) IN GENERAL.—Any election under subsection (a) shall be made not later than the due date for the return of tax for the taxable year described in subsection (a).

"(2) PARTNERSHIPS AND S CORPORATIONS.—In the case of a sale or exchange described in subsection (a) by a partnership or S corporation, the election under subsection (a) shall be made at the partner or shareholder level. The Secretary may prescribe such regulations or other guidance as necessary to carry out the purposes of this paragraph.

"(d) DEFINITIONS.—For purposes of this section—

"(1) APPLICABLE NET TAX LIABILITY.—

"(A) IN GENERAL.—The applicable net tax liability with respect to the sale or exchange of any property described in subsection (a) is the excess (if any) of—

"(i) such taxpayer's net income tax for the taxable year, over

"(ii) such taxpayer's net income tax for such taxable year determined without regard to any gain recognized from the sale or exchange of such property.

"(B) NET INCOME TAX.—The term 'net income tax' means the regular tax liability reduced by the credits allowed under subparts A, B, and D of part IV of subchapter A.

"(2) QUALIFIED FARMLAND PROPERTY.—

"(A) IN GENERAL.—The term 'qualified farmland property' means real property located in the United States—

"(i) which—

"(I) has been used by the taxpayer as a farm for farming purposes, or

"(II) leased by the taxpayer to a qualified farmer for farming purposes,

during substantially all of the 10-year period ending on the date of the qualified sale or exchange, and

"(ii) which is subject to a covenant or other legally enforceable restriction which prohibits the use of such property other than as a farm for farming purposes for any period before the date that is 10 years after the date of the sale or exchange described in subsection (a).

For purposes of clause (i), property which is used or leased by a partnership or S corporation in a manner described in such clause shall be treated as used or leased in such manner by each person who holds a direct or indirect interest in such partnership or S corporation.

"(B) FARM; FARMING PURPOSES.—The terms 'farm' and 'farming purposes' have the respective meanings given such terms under section 2032A(e).

"(3) QUALIFIED FARMER.—The term 'qualified farmer' means any individual who is actively engaged in farming (within the meaning of subsections (b) and (c) of section 1001 of the Food Security Act of 1986 (7 U.S.C. 1308–1(b) and (c))).

"(e) RETURN REQUIREMENT.—A taxpayer making an election under subsection (a) shall include with the return for the taxable year of the sale or exchange described in subsection (a) a copy of the covenant or other legally enforceable restriction described in subsection (d)(2)(A)(ii).".

(b) CLERICAL AMENDMENT.—The table of sections for part IV of subchapter O of chapter 1 is amended by redesignating the item relating to section 1062 as relating to section 1063 and by inserting after the item relating to section 1061 the following new item:

"Sec. 1062. Gain from the sale or exchange of qualified farmland property to qualified farmers.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to sales or exchanges in taxable years beginning after the date of the enactment of this Act.

SEC. 70438. EXTENSION OF RULES FOR TREATMENT OF CERTAIN DISASTER-RELATED PERSONAL CASUALTY LOSSES.

For purposes of applying section 304(b) of the Taxpayer Certainty and Disaster Tax Relief Act of 2020 (division EE of Public Law 116–260), section 301 of such Act shall be applied by substituting the date of the enactment of this section for "the date of the enactment of this Act" each place it appears.

SEC. 70439. RESTORATION OF TAXABLE REIT SUBSIDIARY ASSET TEST.

(a) IN GENERAL.—Section 856(c)(4)(B)(ii) is amended by striking "20 percent" and inserting "25 percent".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

CHAPTER 5—ENDING GREEN NEW DEAL SPENDING, PROMOTING AMERICA-FIRST ENERGY, AND OTHER REFORMS

Subchapter A—Termination of Green New Deal Subsidies

SEC. 70501. TERMINATION OF PREVIOUSLY-OWNED CLEAN VEHICLE CREDIT.

Section 25E(g) is amended by striking "December 31, 2032" and inserting "September 30, 2025".

SEC. 70502. TERMINATION OF CLEAN VEHICLE CREDIT.

(a) IN GENERAL.—Section 30D(h) is amended by striking "placed in service after December 31, 2032" and inserting "acquired after September 30, 2025".

(b) CONFORMING AMENDMENTS.—Section 30D(e) is amended—

(1) in paragraph (1)(B)—

(A) in clause (iii), by inserting "and" after the comma at the end,

(B) in clause (iv), by striking ", and" and inserting a period, and

(C) by striking clause (v), and

(2) in paragraph (2)(B)—

(A) in clause (ii), by inserting "and" after the comma at the end,

(B) in clause (iii), by striking the comma at the end and inserting a period, and

(C) by striking clauses (iv) through (vi).

SEC. 70503. TERMINATION OF QUALIFIED COMMERCIAL CLEAN VEHICLES CREDIT.

Section 45W(g) is amended by striking "December 31, 2032" and inserting "September 30, 2025".

SEC. 70504. TERMINATION OF ALTERNATIVE FUEL VEHICLE REFUELING PROPERTY CREDIT.

Section 30C(i) is amended by striking "December 31, 2032" and inserting "June 30, 2026".

SEC. 70505. TERMINATION OF ENERGY EFFICIENT HOME IMPROVEMENT CREDIT.

(a) IN GENERAL.—Section 25C(h) is amended by striking "placed in service" and all that follows through "December 31, 2032" and inserting "placed in service after December 31, 2025".

(b) CONFORMING AMENDMENT.—Section 25C(d)(2)(C) is amended to read as follows:

"(C) Any oil furnace or hot water boiler which—

"(i) meets or exceeds 2021 Energy Star efficiency criteria, and

"(ii) is rated by the manufacturer for use with fuel blends at least 20 percent of the volume of which consists of an eligible fuel.".

SEC. 70506. TERMINATION OF RESIDENTIAL CLEAN ENERGY CREDIT.

(a) IN GENERAL.—Section 25D(h) is amended by striking "to property placed in service after December 31, 2034" and inserting "with respect to any expenditures made after December 31, 2025".

(b) CONFORMING AMENDMENTS.—Section 25D(g) is amended—

(1) in paragraph (2), by inserting "and" after the comma at the end,

(2) in paragraph (3), by striking " and before January 1, 2033, 30 percent," and inserting "30 percent.", and

(3) by striking paragraphs (4) and (5).

SEC. 70507. TERMINATION OF ENERGY EFFICIENT COMMERCIAL BUILDINGS DEDUCTION.

Section 179D is amended by adding at the end the following new subsection:

"(i) TERMINATION.—This section shall not apply with respect to property the construction of which begins after June 30, 2026.".

SEC. 70508. TERMINATION OF NEW ENERGY EFFICIENT HOME CREDIT.

Section 45L(h) is amended by striking "December 31, 2032" and inserting "June 30, 2026".

SEC. 70509. TERMINATION OF COST RECOVERY FOR ENERGY PROPERTY.

(a) ENERGY PROPERTY.—Section 168(e)(3)(B)(vi), as amended by section 13703 of Public Law 117–169, is amended—

(1) by striking subclause (I), and

(2) by redesignating subclauses (II) and (III) as subclauses (I) and (II), respectively.

(b) EFFECTIVE DATE.—The amendments made by subsection (a) shall apply to property the construction of which begins after December 31, 2024.

SEC. 70510. MODIFICATIONS OF ZERO-EMISSION NUCLEAR POWER PRODUCTION CREDIT.

(a) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—Section 45U(c) is amended by adding at the end the following new paragraph:

"(3) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—No credit shall be determined under subsection (a) for any taxable year beginning after the date of enactment of this paragraph if the taxpayer is a specified foreign entity (as defined in section 7701(a)(51)(B)).

"(B) OTHER PROHIBITED FOREIGN ENTITIES.—No credit shall be determined under subsection (a) for any taxable year beginning after the date which is 2 years after the date of enactment of this paragraph if the taxpayer is a foreign-influenced entity (as defined in section 7701(a)(51)(D), without regard to clause (i)(II) thereof).".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after the date of enactment of this Act.

SEC. 70511. TERMINATION OF CLEAN HYDROGEN PRODUCTION CREDIT.

Section 45V(c)(3)(C) is amended by striking "January 1, 2033" and inserting "January 1, 2028".

SEC. 70512. TERMINATION AND RESTRICTIONS ON CLEAN ELECTRICITY PRODUCTION CREDIT.

(a) TERMINATION FOR WIND AND SOLAR FACILITIES.—Section 45Y(d) is amended—

(1) in paragraph (1), by striking "The amount of" and inserting "Subject to paragraph (4), the amount of", and

(2) by striking paragraph (3) and inserting the following new paragraphs:

"(3) APPLICABLE YEAR.—For purposes of this subsection, the term 'applicable year' means calendar year 2032.

"(4) TERMINATION FOR WIND AND SOLAR FACILITIES.—

"(A) IN GENERAL.—This section shall not apply with respect to any applicable facility placed in service after December 31, 2027.

"(B) APPLICABLE FACILITY.—For purposes of this paragraph, the term 'applicable facility' means a qualified facility which—

"(i) uses wind to produce electricity (within the meaning of such term as used in section 45(d)(1), as determined without regard to any requirement under such section with respect to the date on which construction of property begins), or

"(ii) uses solar energy to produce electricity (within the meaning of such term as used in section 45(d)(4), as determined without regard to any requirement under such section with respect to the date on which construction of property begins).".

(b) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—Section 45Y is amended—

(1) in subsection (b)(1), by adding at the end the following new subparagraph:

"(E) MATERIAL ASSISTANCE FROM PROHIBITED FOREIGN ENTITIES.—The term 'qualified facility' shall not include any facility for which construction begins after December 31, 2025, if the construction of such facility includes any material assistance from a prohibited foreign entity (as defined in section 7701(a)(52)).", and

(2) in subsection (g), by adding at the end the following new paragraph:

"(13) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—No credit shall be determined under subsection (a) for any taxable year if the taxpayer is—

"(i) a specified foreign entity (as defined in section 7701(a)(51)(B)), or

"(ii) a foreign-influenced entity (as defined in section 7701(a)(51)(D), without regard to clause (i)(II) thereof).

"(B) EFFECTIVE CONTROL.—In the case of a taxpayer for which section 7701(a)(51)(D)(i)(II) is determined to apply for any taxable year, no credit shall be determined under subsection (a) for such taxable year if such determination relates to a qualified facility described in subsection (b)(1).".

(c) DEFINITIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—Section 7701(a) is amended by adding at the end the following new paragraphs:

"(51) PROHIBITED FOREIGN ENTITY.—

"(A) IN GENERAL.—

"(i) DEFINITION.—The term 'prohibited foreign entity' means a specified foreign entity or a foreign-influenced entity.

"(ii) DETERMINATION.—

"(I) IN GENERAL.—Subject to subclause (II), for any taxable year, the determination as to whether an entity is a specified foreign entity or foreign-influenced entity shall be made as of the last day of such taxable year.

"(II) INITIAL TAXABLE YEAR.—For purposes of the first taxable year beginning after the date of enactment of this paragraph, the determination as to whether an entity is a specified foreign entity described in clauses (i) through (iv) of subparagraph (B) shall be made as of the first day of such taxable year.

"(B) SPECIFIED FOREIGN ENTITY.—For purposes of this paragraph, the term 'specified foreign entity' means—

"(i) a foreign entity of concern described in subparagraph (A), (B), (D), or (E) of section 9901(8) of the William M. (Mac) Thornberry National Defense Authorization Act for Fiscal Year 2021 (Public Law 116–283; 15 U.S.C. 4651),

"(ii) an entity identified as a Chinese military company operating in the United States in accordance with section 1260H of the William M. (Mac) Thornberry National Defense Authorization Act for Fiscal Year 2021 (Public Law 116–283; 10 U.S.C. 113 note),

"(iii) an entity included on a list required by clause (i), (ii), (iv), or (v) of section 2(d)(2)(B) of Public Law 117–78 (135 Stat. 1527),

"(iv) an entity specified under section 154(b) of the National Defense Authorization Act for Fiscal Year 2024 (Public Law 118–31; 10 U.S.C. note prec. 4651), or

"(v) a foreign-controlled entity.

"(C) FOREIGN-CONTROLLED ENTITY.—For purposes of subparagraph (B), the term 'foreign-controlled entity' means—

"(i) the government (including any level of government below the national level) of a covered nation,

"(ii) an agency or instrumentality of a government described in clause (i),

"(iii) a person who is a citizen or national of a covered nation, provided that such person is not an individual who is a citizen, national, or lawful permanent resident of the United States,

"(iv) an entity or a qualified business unit (as defined in section 989(a)) incorporated or organized under the laws of, or having its principal place of business in, a covered nation, or

"(v) an entity (including subsidiary entities) controlled (as determined under subparagraph (G)) by an entity described in clause (i), (ii), (iii), or (iv).

"(D) FOREIGN-INFLUENCED ENTITY.—

"(i) IN GENERAL.—For purposes of subparagraph (A), the term 'foreign-influenced entity' means an entity—

"(I) with respect to which, during the taxable year—

"(aa) a specified foreign entity has the direct authority to appoint a covered officer of such entity,

"(bb) a single specified foreign entity owns at least 25 percent of such entity,

"(cc) one or more specified foreign entities own in the aggregate at least 40 percent of such entity, or

"(dd) at least 15 percent of the debt of such entity has been issued, in the aggregate, to 1 or more specified foreign entities, or

"(II) which, during the previous taxable year, made a payment to a specified foreign entity pursuant to a contract, agreement, or other arrangement which entitles such specified foreign entity (or an entity related to such specified foreign entity) to exercise effective control over—

"(aa) any qualified facility or energy storage technology of the taxpayer (or any person related to the taxpayer), or "(bb) with respect to any eligible component produced by the taxpayer (or any person related to the taxpayer)—

"(AA) the extraction, processing, or recycling of any applicable critical mineral, or

"(BB) the production of an eligible component which is not an applicable critical mineral.

"(ii) EFFECTIVE CONTROL.—

"(I) IN GENERAL.—

"(aa) GENERAL RULE.—Subject to subclause (II), for purposes of clause (i)(II), the term 'effective control' means 1 or more agreements or arrangements similar to those described in subclauses (II) and (III) which provide 1 or more contractual counterparties of a taxpayer with specific authority over key aspects of the production of eligible components, energy generation in a qualified facility, or energy storage which are not included in the measures of control through authority, ownership, or debt held which are described in clause (i)(I).

"(bb) GUIDANCE.—The Secretary shall issue such guidance as is necessary to carry out the purposes of this clause, including the establishment of rules to prevent entities from evading, circumventing, or abusing the application of the restrictions described subparagraph (C) and subclauses (II) and (III) of this clause through a contract, agreement, or other arrangement.

"(II) APPLICATION OF RULES PRIOR TO ISSUANCE OF GUIDANCE.—During any period prior to the date that the guidance described in subclause (I)(bb) is issued by the Secretary, for purposes of clause (i)(II), the term 'effective control' means the unrestricted contractual right of a contractual counterparty to—

"(aa) determine the quantity or timing of production of an eligible component produced by the taxpayer,

"(bb) determine the amount or timing of activities related to the production of electricity undertaken at a qualified facility of the taxpayer or the storage of electrical energy in energy storage technology of the taxpayer,

"(cc) determine which entity may purchase or use the output of a production unit of the taxpayer that produces eligible components,

"(dd) determine which entity may purchase or use the output of a qualified facility of the taxpayer,

"(ee) restrict access to data critical to production or storage of energy undertaken at a qualified facility of the taxpayer, or to the site of production or any part of a qualified facility or energy storage technology of the taxpayer, to the personnel or agents of such contractual counterparty, or

"(ff) on an exclusive basis, maintain, repair, or operate any plant or equipment which is necessary to the production by the taxpayer of eligible components or electricity.

"(III) LICENSING AND OTHER AGREEMENTS.—

"(aa) IN GENERAL.—In addition to subclause (II), for purposes of clause (i)(II), the term 'effective control' means, with respect to a licensing agreement for the provision of intellectual property (or any other contract, agreement or other arrangement entered into with a contractual counterparty related to such licensing agreement) with respect to a qualified facility, energy storage technology, or the production of an eligible component, any of the following:

"(AA) A contractual right retained by the contractual counterparty to specify or otherwise direct 1 or more sources of components, subcomponents, or applicable critical minerals utilized in a qualified facility, energy storage technology, or in the production of an eligible component.

"(BB) A contractual right retained by the contractual counterparty to direct the operation of any qualified facility, any energy storage technology, or any production unit that produces an eligible component.

"(CC) A contractual right retained by the contractual counterparty to limit the taxpayer's utilization of intellectual property related to the operation of a qualified facility or energy storage technology, or in the production of an eligible component.

"(DD) A contractual right retained by the contractual counterparty to receive royalties under the licensing agreement or any similar agreement (or payments under any related agreement) beyond the 10th year of the agreement (including modifications or extensions thereof).

"(EE) A contractual right retained by the contractual counterparty to direct or otherwise require the taxpayer to enter into an agreement for the provision of services for a duration longer than 2 years (including any modifications or extensions thereof).

"(FF) Such contract, agreement, or other arrangement does not provide the licensee with all the technical data, information, and know-how necessary to enable the licensee to produce the eligible component or components subject to the contract, agreement, or other arrangement without further involvement from the contractual counterparty or a specified foreign entity.

"(GG) Such contract, agreement, or other arrangement was entered into (or modified) on or after the date of enactment of this paragraph.

"(bb) EXCEPTION.—

"(AA) IN GENERAL.—Item (aa) shall not apply in the case of a bona fide purchase or sale of intellectual property.

"(BB) BONA FIDE PURCHASE OR SALE.—For purposes of item (aa), any purchase or sale of intellectual property where the agreement provides that ownership of the intellectual property reverts to the contractual counterparty after a period of time shall not be considered a bona-fide purchase or sale.

"(IV) PERSONS RELATED TO THE TAXPAYER.—For purposes of subclauses (I), (II), and (III), the term 'taxpayer' shall include any person related to the taxpayer.

"(V) CONTRACTUAL COUNTERPARTY.—For purposes of this clause, the term 'contractual counterparty' means an entity with which the taxpayer has entered into a contract, agreement, or other arrangement.

"(iii) GUIDANCE.—Not later than December 31, 2026, the Secretary shall issue such guidance as is necessary to carry out the purposes of this subparagraph, including establishment of rules to prevent entities from evading, circumventing, or abusing the application of the restrictions against impermissible technology licensing arrangements with specified foreign entities, such as through temporary transfers of intellectual property, retention by a specified foreign entity of a reversionary interest in transferred intellectual property, or otherwise.

"(E) PUBLICLY TRADED ENTITIES.—

"(i) IN GENERAL.—

"(I) NONAPPLICATION OF CERTAIN FOREIGN-CONTROLLED ENTITY RULES.—Subparagraph (C)(v) shall not apply in the case of any entity the securities of which are regularly traded on—

"(aa) a national securities exchange which is registered with the Securities and Exchange Commission,

"(bb) the national market system established pursuant to section 11A of the Securities and Exchange Act of 1934, or

"(cc) any other exchange or other market which the Secretary has determined in guidance issued under section 1296(e)(1)(A)(ii) has rules adequate to carry out the purposes of part VI of subchapter P of chapter 1 of subtitle A.

"(II) NONAPPLICATION OF CERTAIN FOREIGN-INFLUENCED ENTITY RULES.—Subparagraph (D)(i)(I) shall not apply in the case of any entity—

"(aa) the securities of which are regularly traded in a manner described in subclause (I), or

"(bb) for which not less than 80 percent of the equity securities of such entity are owned directly or indirectly by an entity which is described in item (aa).

"(III) EXCLUSION OF EXCHANGES OR MARKETS IN COVERED NATIONS.—Subclause (I)(cc) shall not apply with respect to any exchange or market which—

"(aa) is incorporated or organized under the laws of a covered nation, or

"(bb) has its principal place of business in a covered nation.

"(ii) ADDITIONAL FOREIGN-CONTROLLED ENTITY REQUIREMENTS FOR PUBLICLY TRADED COMPANIES.—In the case of an entity described in clause (i)(I), such entity shall be deemed to be a foreign-controlled entity under subparagraph (C)(v) if such entity is controlled (as determined under subparagraph (G)) by—

"(I) 1 or more specified foreign entities (as determined without regard to subparagraph (B)(v)) that are each required to report their beneficial ownership pursuant to a rule described in clause (iii)(I)(bb), or

"(II) 1 or more foreign-controlled entities (as determined without regard to subparagraph (C)(v)) that are each required to report their beneficial ownership pursuant to a rule described in such clause.

"(iii) ADDITIONAL FOREIGN-INFLUENCED ENTITY REQUIREMENTS FOR PUBLICLY TRADED COMPANIES.—In the case of an entity described in clause (i)(II), such entity shall be deemed to be a foreign-influenced entity under subparagraph (D)(i)(I) if—

"(I) during the taxable year—

"(aa) a specified foreign entity has the authority to appoint a covered officer of such entity,

"(bb) a single specified foreign entity required to report its beneficial ownership under Rule 13d-3 of the Securities and Exchange Act of 1934 (or, in the case of an exchange or market described in clause (i)(I)(cc), an equivalent rule) owns not less than 25 percent of such entity, or

"(cc) 1 or more specified foreign entities that are each required to report their beneficial ownership under Rule 13d-3 of the Securities and Exchange Act of 1934 own, in the aggregate, not less than 40 percent of such entity, or

"(II) such entity has issued debt, as part of an original issuance, in excess of 15 percent of its publicly-traded debt to 1 or more specified foreign entities.

"(F) COVERED OFFICER.—For purposes of this paragraph, the term 'covered officer' means, with respect to an entity—

"(i) a member of the board of directors, board of supervisors, or equivalent governing body,

"(ii) an executive-level officer, including the president, chief executive officer, chief operating officer, chief financial officer, general counsel, or senior vice president, or

"(iii) an individual having powers or responsibilities similar to those of officers or members described in clause (i) or (ii).

"(G) DETERMINATION OF CONTROL.—For purposes of subparagraph (C)(v), the term 'control' means—

"(i) in the case of a corporation, ownership (by vote or value) of more than 50 percent of the stock in such corporation,

"(ii) in the case of a partnership, ownership of more than 50 percent of the profits interests or capital interests in such partnership, or

"(iii) in any other case, ownership of more than 50 percent of the beneficial interests in the entity.

"(H) DETERMINATION OF OWNERSHIP.—For purposes of this paragraph, section 318(a)(2) shall apply for purposes of determining ownership of stock in a corporation. Similar principles shall apply for purposes of determining ownership of interests in any other entity.

"(I) OTHER DEFINITIONS.—For purposes of this paragraph—

"(i) APPLICABLE CRITICAL MINERAL.—The term 'applicable critical mineral' has the same meaning given such term under section 45X(c)(6).

"(ii) COVERED NATION.—The term 'covered nation' has the same meaning given such term under section 4872(f)(2) of title 10, United States Code.

"(iii) ELIGIBLE COMPONENT.—The term 'eligible component' has the same meaning given such term under section 45X(c)(1).

"(iv) ENERGY STORAGE TECHNOLOGY.—The term 'energy storage technology' has the same meaning given such term under section 48E(c)(2).

"(v) QUALIFIED FACILITY.—The term 'qualified facility' means—

"(I) a qualified facility, as defined in section 45Y(b)(1), and

"(II) a qualified facility, as defined in section 48E(b)(3).

"(vi) RELATED.—The term 'related' shall have the same meaning given such term under sections 267(b) and 707(b).

"(J) BEGINNING OF CONSTRUCTION.—For purposes of applying any provision under this paragraph, the beginning of construction with respect to any property shall be determined pursuant to rules similar to the rules under Internal Revenue Service Notice 2013–29 and Internal Revenue Service Notice 2018-59 (as well as any subsequently issued guidance clarifying, modifying, or updating either such Notice), as in effect on January 1, 2025.

"(K) REGULATIONS AND GUIDANCE.—The Secretary may prescribe such regulations and guidance as may be necessary or appropriate to carry out the provisions of this paragraph, including rules to prevent the circumvention of any rules or restrictions with respect to prohibited foreign entities.

"(52) MATERIAL ASSISTANCE FROM A PROHIBITED FOREIGN ENTITY.—

"(A) IN GENERAL.—The term 'material assistance from a prohibited foreign entity' means—

"(i) with respect to any qualified facility or energy storage technology, a material assistance cost ratio which is less than the threshold percentage applicable under subparagraph (B), or

"(ii) with respect to any facility which produces eligible components, a material assistance cost ratio which is less than the threshold percentage applicable under subparagraph (C).

"(B) THRESHOLD PERCENTAGE FOR QUALIFIED FACILITIES AND ENERGY STORAGE TECHNOLOGY.—For purposes of subparagraph (A)(i), the threshold percentage shall be—

"(i) in the case of a qualified facility the construction of which begins—

"(I) during calendar year 2026, 40 percent,

"(II) during calendar year 2027, 45 percent,

"(III) during calendar year 2028, 50 percent,

"(IV) during calendar year 2029, 55 percent, and

"(V) after December 31, 2029, 60 percent, and

"(ii) in the case of energy storage technology the construction of which begins—

"(I) during calendar year 2026, 55 percent,

"(II) during calendar year 2027, 60 percent,

"(III) during calendar year 2028, 65 percent,

"(IV) during calendar year 2029, 70 percent, and

"(V) after December 31, 2029, 75 percent.

"(C) THRESHOLD PERCENTAGE FOR ELIGIBLE COMPONENTS.—

"(i) IN GENERAL.—For purposes of subparagraph (A)(ii), the threshold percentage shall be—

"(I) in the case of any solar energy component (as such term is defined in section 45X(c)(3)(A)) which is sold—

"(aa) during calendar year 2026, 50 percent,

"(bb) during calendar year 2027, 60 percent, "(cc) during calendar year 2028, 70 percent,

"(dd) during calendar year 2029, 80 percent, and

"(ee) after December 31, 2029, 85 percent,

"(II) in the case of any wind energy component (as such term is defined in section 45X(c)(4)(A)) which is sold—

"(aa) during calendar year 2026, 85 percent, and

"(bb) during calendar year 2027, 90 percent,

"(III) in the case of any inverter described in subparagraphs (B) through (G) of section 45X(c)(2) which is sold—

"(aa) during calendar year 2026, 50 percent,

"(bb) during calendar year 2027, 55 percent,

"(cc) during calendar year 2028, 60 percent,

"(dd) during calendar year 2029, 65 percent, and

"(ee) after December 31, 2029, 70 percent,

"(IV) in the case of any qualifying battery component (as such term is defined in section 45X(c)(5)(A)) which is sold—

"(aa) during calendar year 2026, 60 percent,

"(bb) during calendar year 2027, 65 percent,

"(cc) during calendar year 2028, 70 percent,

"(dd) during calendar year 2029, 80 percent, and

"(ee) after December 31, 2029, 85 percent, and

"(V) subject to clause (ii), in the case of any applicable critical mineral (as such term is defined in section 45X(c)(6)) which is sold—

"(aa) after December 31, 2025, and before January 1, 2030, 0 percent,

"(bb) during calendar year 2030, 25 percent,

"(cc) during calendar year 2031, 30 percent,

"(dd) during calendar year 2032, 40 percent, and

"(ee) after December 31, 2032, 50 percent.

"(ii) ADJUSTED THRESHOLD PERCENTAGE FOR APPLICABLE CRITICAL MINERALS.—Not later than December 31, 2027, the Secretary shall issue threshold percentages for each of the applicable critical minerals described in section 45X(c)(6)), which shall—

"(I) apply in lieu of the threshold percentage determined under clause (i)(V) for each calendar year, and

"(II) equal or exceed the threshold percentage which would otherwise apply with respect to such applicable critical mineral under such clause for such calendar year, taking into account—

"(aa) domestic geographic availability,

"(bb) supply chain constraints,

"(cc) domestic processing capacity needs, and

"(dd) national security concerns.

"(D) MATERIAL ASSISTANCE COST RATIO.—

"(i) QUALIFIED FACILITIES AND ENERGY STORAGE TECHNOLOGY.—For purposes of subparagraph (A)(i), the term 'material assistance cost ratio' means the amount (expressed as a percentage) equal to the quotient of—

"(I) an amount equal to—

"(aa) the total direct costs to the taxpayer attributable to all manufactured products (including components) which are incorporated into the qualified facility or energy storage technology upon completion of construction, minus

"(bb) the total direct costs to the taxpayer attributable to all manufactured products (including components) which are—

"(AA) incorporated into the qualified facility or energy storage technology upon completion of construction, and

"(BB) mined, produced, or manufactured by a prohibited foreign entity, divided by

"(II) the amount described in subclause (I)(aa).

"(ii) ELIGIBLE COMPONENTS.—For purposes of subparagraph (A)(ii), the term 'material assistance cost ratio' means the amount (expressed as a percentage) equal to the quotient of—

"(I) an amount equal to—

"(aa) with respect to an eligible component, the total direct material costs that are paid or incurred (within the meaning of section 461 and any regulations issued under section 263A) by the taxpayer for production of such eligible component, minus

"(bb) with respect to an eligible component, the total direct material costs that are paid or incurred (within the meaning of section 461 and any regulations issued under section 263A) by the taxpayer for production of such eligible component that are mined, produced, or manufactured by a prohibited foreign entity, divided by

"(II) the amount described in subclause (I)(aa).

"(iii) SAFE HARBOR TABLES.—

"(I) IN GENERAL.—Not later than December 31, 2026, the Secretary shall issue safe harbor tables (and such other guidance as deemed necessary) to—

"(aa) identify the percentage of total direct costs of any manufactured product which is attributable to a prohibited foreign entity,

"(bb) identify the percentage of total direct material costs of any eligible component which is attributable to a prohibited foreign entity, and

"(cc) provide all rules necessary to determine the amount of a taxpayer's material assistance from a prohibited foreign entity within the meaning of this paragraph.

"(II) SAFE HARBORS PRIOR TO ISSUANCE.—For purposes of this paragraph, prior to the date on which the Secretary issues the safe harbor tables described in subclause (I), and for construction of a qualified facility or energy storage technology which begins on or before the date which is 60 days after the date of issuance of such tables, a taxpayer may—

"(aa) use the tables included in Internal Revenue Service Notice 2025–08 to establish the percentage of the total direct costs of any listed eligible component and any manufactured product, and

"(bb) rely on a certification by the supplier of the manufactured product, eligible component, or constituent element, material, or subcomponent of an eligible component—

"(AA) of the total direct costs or the total direct material costs, as applicable, of such product or component that was not produced or manufactured by a prohibited foreign entity, or

"(BB) that such product or component was not produced or manufactured by a prohibited foreign entity.

"(III) EXCEPTION.—Notwithstanding subclauses (I) and (II)—

"(aa) if the taxpayer knows (or has reason to know) that a manufactured product or eligible component was produced or manufactured by a prohibited foreign entity, the taxpayer shall treat all direct costs with respect to such manufactured product, or all direct material costs with respect to such eligible component, as attributable to a prohibited foreign entity, and

"(bb) if the taxpayer knows (or has reason to know) that the certification referred to in subclause (II)(bb) pertaining to a manufactured product or eligible component is inaccurate, the taxpayer may not rely on such certification.

"(IV) CERTIFICATION REQUIREMENT.—In a manner consistent with Treasury Regulation section 1.45X–4(c)(4)(i) (as in effect on the date of enactment of this paragraph), the certification referred to in subclause (II)(bb) shall—

"(aa) include—

"(AA) the supplier's employer identification number, or

"(BB) any such similar identification number issued by a foreign government,

"(bb) be signed under penalties of perjury,

"(cc) be retained by the supplier and the taxpayer for a period of not less than 6 years and shall be provided to the Secretary upon request, and

"(dd) be from the supplier from which the taxpayer purchased any manufactured product, eligible component, or constituent elements, materials, or subcomponents of an eligible component, stating—

"(AA) that such property was not produced or manufactured by a prohibited foreign entity and that the supplier does not know (or have reason to know) that any prior supplier in the chain of production of that property is a prohibited foreign entity,

"(BB) for purposes of section 45X, the total direct material costs for each component, constituent element, material, or subcomponent that were not produced or manufactured by a prohibited foreign entity, or

"(CC) for purposes of section 45Y or section 48E, the total direct costs attributable to all manufactured products that were not produced or manufactured by a prohibited foreign entity.

"(iv) EXISTING CONTRACT.—Upon the election of the taxpayer (in such form and manner as the Secretary shall designate), in the case of any manufactured product, eligible component, or constituent element, material, or subcomponent of an eligible component which is—

"(I) acquired by the taxpayer, or manufactured or assembled by or for the taxpayer, pursuant to a binding written contract which was entered into prior to June 16, 2025, and

"(II)(aa) placed into service before January 1, 2030 (or, in the case of an applicable facility, as defined in section 45Y(d)(4)(B), before January 1, 2028) in a facility the construction of which began before August 1, 2025, or

"(bb) in the case of a constituent element, material, or subcomponent, used in a product sold before January 1, 2030,

the cost to the taxpayer with respect to such product, component, element, material, or subcomponent shall not be included for purposes of determining the material assistance cost ratio under this subparagraph.

"(v) ANTI-CIRCUMVENTION RULES.—The Secretary shall prescribe such regulations and guidance as may be necessary or appropriate to prevent circumvention of the rules under this subparagraph, including prevention of—

"(I) any abuse of the exception provided under clause (iv) through the stockpiling of any manufactured product, eligible component, or constituent element, material, or subcomponent of an eligible component during any period prior to the application of the requirements under this paragraph, or

"(II) any evasion with respect to the requirements of this subparagraph where the facts and circumstances demonstrate that the beginning of construction of a qualified facility or energy storage technology has not in fact occurred.

"(E) OTHER DEFINITIONS.—For purposes of this paragraph—

"(i) ELIGIBLE COMPONENT.—The term 'eligible component' means—

"(I) any property described in section 45X(c)(1), or

"(II) any component which is identified by the Secretary pursuant to regulations or guidance issued under subparagraph (G).

"(ii) ENERGY STORAGE TECHNOLOGY.—The term 'energy storage technology' has the same meaning given such term under section 48E(c)(2).

"(iii) MANUFACTURED PRODUCT.—The term 'manufactured product' means—

"(I) a manufactured product which is a component of a qualified facility, as described in section 45Y(g)(11)(B) and any guidance issued thereunder, or

"(II) any product which is identified by the Secretary pursuant to regulations or guidance issued under subparagraph (G).

"(iv) QUALIFIED FACILITY.—The term 'qualified facility' means—

"(I) a qualified facility, as defined in section 45Y(b)(1),

"(II) a qualified facility, as defined in section 48E(b)(3), and

"(III) any qualified interconnection property (as defined in section 48E(b)(4)) which is part of the qualified investment with respect to a qualified facility (as described in section 48E(b)(1)).

"(F) DETERMINATION OF OWNERSHIP; BEGINNING OF CONSTRUCTION.—Rules similar to the rules under subparagraphs (H) and (J) of paragraph (51) shall apply for purposes of this paragraph.

"(G) REGULATIONS AND GUIDANCE.—The Secretary may prescribe such regulations and guidance as may be necessary or appropriate to carry out the provisions of this paragraph, including—

"(i) identification of components or products for purposes of clauses (i) and (iii) of subparagraph (E), and

"(ii) for purposes of subparagraph (A)(ii), rules to address facilities which produce more than one eligible component.".

(d) DENIAL OF CREDIT FOR CERTAIN WIND AND SOLAR LEASING ARRANGEMENTS.—Section 45Y is amended by adding at the end the following new subsection:

"(h) DENIAL OF CREDIT FOR WIND AND SOLAR LEASING ARRANGEMENTS.—No credit shall be determined under this section with respect to any production of electricity during the taxable year with respect to property described in paragraph (1) or (4) of section 25D(d) (as applied by substituting 'lessee' for 'taxpayer') if the taxpayer rents or leases such property to a third party during such taxable year.".

(e) EMISSIONS RATES TABLES.—Section 45Y(b)(2)(C) is amended by adding at the end the following new clause:

"(iii) EXISTING STUDIES.—For purposes of clause (i), in determining greenhouse gas emissions rates for types or categories of facilities for the purpose of determining whether a facility satisfies the requirements under paragraph (1), the Secretary shall consider studies published on or before the date of enactment of this clause which demonstrate a net lifecycle greenhouse gas emissions rate which is not greater than zero using widely accepted lifecycle assessment concepts, such as concepts described in standards developed by the International Organization for Standardization.".

(f) NUCLEAR ENERGY COMMUNITIES.—

(1) IN GENERAL.—Section 45(b)(11) is amended—

(A) in subparagraph (B)—

(i) in clause (ii)(II), by striking "or" at the end,

(ii) in clause (iii)(II), by striking the period at the end and inserting ", or", and

(iii) by adding at the end the following new clause:

"(iv) for purposes of any qualified facility which is an advanced nuclear facility, a metropolitan statistical area which has (or, at any time during the period beginning after December 31, 2009, had) 0.17 percent or greater direct employment related to the advancement of nuclear power, including employment related to—

"(I) an advanced nuclear facility,

"(II) advanced nuclear power research and development,

"(III) nuclear fuel cycle research, development, or production, including mining, enrichment, manufacture, storage, disposal, or recycling of nuclear fuel, and

"(IV) the manufacturing or assembly of components used in an advanced nuclear facility.", and

(B) by adding at the end the following new subparagraph:

"(C) ADVANCED NUCLEAR FACILITIES.—

"(i) IN GENERAL.—Subject to clause (ii), for purposes of subparagraph (B)(iv), the term 'advanced nuclear facility' means any nuclear facility the reactor design for which is approved in the manner described in section 45J(d)(2).

"(ii) SPECIAL RULE.—For purposes of clause (i), a facility shall be deemed to have a reactor design which is approved in the manner described in section 45J(d)(2) if the Nuclear Regulatory Commission has authorized construction and issued a site-specific construction permit or combined license with respect to such facility (without regard to whether the reactor design was approved after December 31, 1993).".

(2) NONAPPLICATION FOR CLEAN ELECTRICITY INVESTMENT CREDIT.—Section 48E(a)(3)(A)(i) is amended by inserting ", as applied without regard to clause (iv) thereof" after "section 45(b)(11)(B)".

(g) CONFORMING AMENDMENTS.—Section 45Y(b)(1) is amended—

(1) by redesignating subparagraph (D) as subparagraph (E), and

(2) by inserting after subparagraph (C) the following new subparagraph:

"(D) DETERMINATION OF CAPACITY.—For purposes of subparagraph (C), additions of capacity of a facility shall be determined in any reasonable manner, including based on—

"(i) determinations by, or reports to, the Federal Energy Regulatory Commission (including interconnection agreements), the Nuclear Regulatory Commission, or any similar entity, reflecting additions of capacity,

"(ii) determinations or reports reflecting additions of capacity made by an independent professional engineer,

"(iii) reports to, or issued by, regional transmission organizations or independent system operators reflecting additions of capacity, or

"(iv) any other method or manner provided by the Secretary.".

(h) PROHIBITION ON TRANSFER OF CREDITS TO SPECIFIED FOREIGN ENTITIES.—Section 6418(g) is amended by adding at the end the following new paragraph:

"(5) PROHIBITION ON TRANSFER OF CREDITS TO SPECIFIED FOREIGN ENTITIES.—With respect to any eligible credit described in clause (iii), (iv), (vi), (vii), (viii), or (xi) of subsection (f)(1)(A), an eligible taxpayer may not elect to transfer any portion of such credit to a taxpayer that is a specified foreign entity (as defined in section 7701(a)(51)(B)).".

(i) EXTENSION OF PERIOD OF LIMITATIONS FOR ERRORS RELATING TO DETERMINING OF MATERIAL ASSISTANCE FROM A PROHIBITED FOREIGN ENTITY.—Section 6501 is amended—

(1) by redesignating subsection (o) as subsection (p), and

(2) by inserting after subsection (n) the following new subsection:

"(o) MATERIAL ASSISTANCE FROM A PROHIBITED FOREIGN ENTITY.—In the case of a deficiency attributable to an error with respect to the determination under section 7701(a)(52) for any taxable year, such deficiency may be assessed at any time within 6 years after the return for such year was filed.".

(j) IMPOSITION OF ACCURACY-RELATED PENALTIES.—

(1) IN GENERAL.—Section 6662 is amended by adding at the end the following new subsection:

"(m) SUBSTANTIAL UNDERSTATEMENT OF INCOME TAX DUE TO DISALLOWANCE OF APPLICABLE ENERGY CREDITS.—

"(1) IN GENERAL.—In the case of a taxpayer for which there is a disallowance of an applicable energy credit for any taxable year, for purposes of determining whether there is a substantial understatement of income tax for such taxable year, subsection (d)(1) shall be applied—

"(A) in subparagraphs (A) and (B), by substituting '1 percent' for '10 percent' each place it appears, and

"(B) without regard to subparagraph (C).

"(2) DISALLOWANCE OF AN APPLICABLE ENERGY CREDIT.—For purposes of this subsection, the term 'disallowance of an applicable energy credit' means the disallowance of a credit under section 45X, 45Y, or 48E by reason of overstating the material assistance cost ratio (as determined under section 7701(a)(52)) with respect to any qualified facility, energy storage technology, or facility which produces eligible components.".

(2) CONFORMING AMENDMENT.—Section 6417(d)(6) is amended by adding at the end the following new subparagraph:

"(D) DISALLOWANCE OF AN APPLICABLE ENERGY CREDIT.—In the case of an applicable entity which made an election under subsection (a) with respect to an applicable credit for which there is a disallowance described in section 6662(m)(2), subparagraph (A) shall apply with respect to any excessive payment resulting from such disallowance.".

(k) PENALTY FOR SUBSTANTIAL MISSTATEMENTS ON CERTIFICATION PROVIDED BY SUPPLIER.—

(1) IN GENERAL.—Part I of subchapter B of chapter 68 is amended by inserting after section 6695A the following new section:

"SEC. 6695B. PENALTY FOR SUBSTANTIAL MISSTATEMENTS ON CERTIFICATION PROVIDED BY SUPPLIER.

"(a) IMPOSITION OF PENALTY.—If—

"(1) a person—

"(A) provides a certification described in clause (iii)(II)(bb) of section 7701(a)(52)(D) with respect to any manufactured product, eligible component, or constituent element, material, or subcomponent of an eligible component, and

"(B) knows, or reasonably should have known, that the certification would be used in connection with a determination under such section,

"(2) such person knows, or reasonably should have known, that such certification is inaccurate or false with respect to—

"(A) whether such property was produced or manufactured by a prohibited foreign entity, or

"(B) the total direct costs or total direct material costs of such property that was not produced or manufactured by a prohibited foreign entity that were provided on such certification, and

"(3) the inaccuracy or falsity described in paragraph (2) resulted in the disallowance of an applicable energy credit (as defined in section 6662(m)(2)) and an understatement of income tax (within the meaning of section 6662(d)(2)) for the taxable year in an amount which exceeds the lesser of—

"(A) 5 percent of the tax required to be shown on the return for the taxable year, or

"(B) $100,000,

then such person shall pay a penalty in the amount determined under subsection (b).

"(b) AMOUNT OF PENALTY.—The amount of the penalty imposed under subsection (a) on any person with respect to a certification shall be equal to the greater of—

"(1) 10 percent of the amount of the underpayment (as defined in section 6664(a)) solely attributable to the inaccuracy or falsity described in subsection (a)(2), or

"(2) $5,000.

"(c) EXCEPTION.—No penalty shall be imposed under subsection (a) if the person establishes to the satisfaction of the Secretary that any inaccuracy or falsity described in subsection (a)(2) is due to a reasonable cause and not willful neglect.

"(d) DEFINITIONS.—Any term used in this section which is also used in section 7701(a)(52) shall have the meaning given such term in such section.".

(2) CLERICAL AMENDMENTS.—

(A) Section 6696 is amended—

(i) in the heading, by striking "**AND 6695A**" and inserting "**6695A, AND 6695B**",

(ii) in subsections (a), (b), and (e), by striking "and 6695A" each place it appears and inserting "6695A, and 6695B",

(iii) in subsection (c), by striking "or 6695A" and inserting "6695A, or 6695B", and

(iv) in subsection (d)—

(I) in paragraph (1), by inserting "(or, in the case of any penalty under section 6695B, 6 years)" after "assessed within 3 years", and

(II) in paragraph (2), by inserting "(or, in the case of any claim for refund of an overpayment of any penalty assessed under section 6695B, 6 years)" after "filed within 3 years".

(B) The table of sections for part I of subchapter B of chapter 68 is amended by inserting after item relating to section 6695A the following new item:

(l) EFFECTIVE DATES.—

(1) IN GENERAL.—Except as provided in paragraphs (2), (3), and (4), the amendments made by this section shall apply to taxable years beginning after the date of enactment of this Act.

(2) MATERIAL ASSISTANCE FROM PROHIBITED FOREIGN ENTITIES.—The amendments made by subsection (b)(1) shall apply to facilities for which construction begins after December 31, 2025.

(3) PENALTY FOR SUBSTANTIAL MISSTATEMENTS ON CERTIFICATION PROVIDED BY SUPPLIER.—The amendments made by subsection (k) shall apply to certifications provided after December 31, 2025.

(4) TERMINATION FOR WIND AND SOLAR FACILITIES.—The amendments made by subsection (a) shall apply to facilities the construction of which begins after the date which is 12 months after the date of enactment of this Act.

SEC. 70513. TERMINATION AND RESTRICTIONS ON CLEAN ELECTRICITY INVESTMENT CREDIT.

(a) TERMINATION FOR WIND AND SOLAR FACILITIES.—Section 48E(e) is amended—

(1) in paragraph (1), by striking "The amount of" and inserting "Subject to paragraph (4), the amount of", and

(2) by adding at the end the following new paragraph:

"(4) TERMINATION FOR WIND AND SOLAR FACILITIES.—

"(A) IN GENERAL.—This section shall not apply to any qualified property placed in service by the taxpayer after December 31, 2027, which is part of an applicable facility.

"(B) APPLICABLE FACILITY.—For purposes of this paragraph, the term 'applicable facility' means a qualified facility which—

"(i) uses wind to produce electricity (within the meaning of such term as used in section 45(d)(1), as determined without regard to any requirement under such section with respect to the date on which construction of property begins), or

"(ii) uses solar energy to produce electricity (within the meaning of such term as used in section 45(d)(4), as determined without regard to any requirement under such section with respect to the date on which construction of property begins).

"(C) EXCEPTION.—This paragraph shall not apply with respect to any energy storage technology which is placed in service at any applicable facility.".

(b) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

(1) IN GENERAL.—Section 48E is amended—

(A) in subsection (b)—

(i) by redesignating paragraph (6) as paragraph (7), and

(ii) by inserting after paragraph (5) the following new paragraph:

"(6) MATERIAL ASSISTANCE FROM PROHIBITED FOREIGN ENTITIES.—The terms 'qualified facility' and 'qualified interconnection property' shall not include any facility or property the construction, reconstruction, or erection of which begins after December 31, 2025, if the construction, reconstruction, or erection of such facility or property includes any material assistance from a prohibited foreign entity (as defined in section 7701(a)(52)).", and

(B) in subsection (c), by adding at the end the following new paragraph:

"(3) MATERIAL ASSISTANCE FROM PROHIBITED FOREIGN ENTITIES.—The term 'energy storage technology' shall not include any property the construction of which begins after December

31, 2025, if the construction of such property includes any material assistance from a prohibited foreign entity (as defined in section 7701(a)(52)).".

(2) ADDITIONAL RESTRICTIONS.—Section 48E(d) is amended by adding at the end the following new paragraph:

"(6) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—No credit shall be determined under subsection (a) for any taxable year if the taxpayer is—

"(i) a specified foreign entity (as defined in section 7701(a)(51)(B)), or

"(ii) a foreign-influenced entity (as defined in section 7701(a)(51)(D), without regard to clause (i)(II) thereof).

"(B) EFFECTIVE CONTROL.—In the case of a taxpayer for which section 7701(a)(51)(D)(i)(II) is determined to apply for any taxable year, no credit shall be determined under subsection (a) for such taxable year if such determination relates to a qualified facility described in subsection (b)(3) or energy storage technology described in subsection (c)(2).".

(3) RECAPTURE.—

(A) IN GENERAL.—Section 50(a) is amended—

(i) by redesignating paragraphs (4) through (6) as paragraphs (5) through (7), respectively,

(ii) by inserting after paragraph (3) the following new paragraph:

"(4) PAYMENTS TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—If there is an applicable payment made by a specified taxpayer before the close of the 10-year period beginning on the date such taxpayer placed in service investment credit property which is eligible for the clean electricity investment credit under section 48E(a), then the tax under this chapter for the taxable year in which such applicable payment occurs shall be increased by 100 percent of the aggregate decrease in the credits allowed under section 38 for all prior taxable years which would have resulted solely from reducing to zero any credit determined under section 46 which is attributable to the clean electricity investment credit under section 48E(a) with respect to such property.

"(B) APPLICABLE PAYMENT.—For purposes of this paragraph, the term 'applicable payment' means, with respect to any taxable year, a payment or payments described in section 7701(a)(51)(D)(i)(II).

"(C) SPECIFIED TAXPAYER.—For purposes of this paragraph, the term 'specified taxpayer' means any taxpayer who has been allowed a credit under section 48E(a) for any taxable year beginning after the date which is 2 years after the date of enactment of this paragraph.",

(iii) in paragraph (5), as redesignated by clause (i), by striking "or any applicable transaction to which paragraph (3)(A) applies," and inserting "any applicable transaction to which paragraph (3)(A) applies, or any applicable payment to which paragraph (4)(A) applies,", and

(iv) in paragraph (7), as redesignated by clause (i), by striking "or (3)" and inserting "(3), or (4)".

(B) CONFORMING AMENDMENTS.—

(i) Section 1371(d)(1) is amended by striking "section 50(a)(5)" and inserting "section 50(a)(6)".

(ii) Section 6418(g)(3) is amended by striking "subsection (a)(5)" each place it appears and inserting "subsection (a)(7)".

(c) DENIAL OF CREDIT FOR EXPENDITURES FOR CERTAIN WIND AND SOLAR LEASING ARRANGEMENTS.—

(1) IN GENERAL.—Section 48E is amended—

(A) by redesignating subsection (i) as subsection (j), and

(B) by inserting after subsection (h) the following new subsection:

"(i) DENIAL OF CREDIT FOR EXPENDITURES FOR WIND AND SOLAR LEASING ARRANGEMENTS.—No credit shall be determined under this section for any qualified investment during the taxable year with respect to property described in paragraph (1) or (4) of section 25D(d) (as applied by substituting 'lessee' for 'taxpayer') if the taxpayer rents or leases such property to a third party during such taxable year.".

(2) CONFORMING RULES.—Section 50 is amended by adding at the end the following new subsection:

"(e) RULES FOR GEOTHERMAL HEAT PUMPS.—For purposes of this section and section 168, the ownership of energy property described in section 48(a)(3)(A)(vii) shall be determined without regard to whether such property is readily usable by a person other than the lessee or service recipient.".

(d) DOMESTIC CONTENT RULES.—Subparagraph (B) of section 48E(a)(3) is amended to read as follows:

"(B) DOMESTIC CONTENT.—Rules similar to the rules of section 48(a)(12) shall apply, except that, for purposes of subparagraph (B) of such section and the application of rules similar to the rules of section 45(b)(9)(B), the adjusted percentage (as determined under section 45(b)(9)(C)) shall be determined as follows:

"(i) In the case of any qualified investment with respect to any qualified facility or energy storage technology the construction of which begins before June 16, 2025, 40 percent (or, in the case of a qualified facility which is an offshore wind facility, 20 percent).

"(ii) In the case of any qualified investment with respect to any qualified facility or energy storage technology the construction of which begins on or after June 16, 2025, and before January 1, 2026, 45 percent (or, in the case of a qualified facility which is an offshore wind facility, 27.5 percent).

"(iii) In the case of any qualified investment with respect to any qualified facility or energy storage technology the construction of which begins during calendar year 2026, 50 percent (or, in the case of a qualified facility which is an offshore wind facility, 35 percent).

"(iv) In the case of any qualified investment with respect to any qualified facility or energy storage technology the construction of which begins after December 31, 2026, 55 percent.".

(e) ELIMINATION OF ENERGY CREDIT FOR CERTAIN ENERGY PROPERTY.—Section 48(a)(2) is amended—

(1) in subparagraph (A)(ii), by striking "2 percent" and inserting "0 percent", and

(2) by adding at the end the following new subparagraph:

"(C) NONAPPLICATION OF INCREASES TO ENERGY PERCENTAGE.—For purposes of energy property described in subparagraph (A)(ii), the energy percentage applicable to such property pursuant to such subparagraph shall not be increased or otherwise adjusted by any provision of this section.".

(f) APPLICATION OF CLEAN ELECTRICITY INVESTMENT CREDIT TO QUALIFIED FUEL CELL PROPERTY.—Section 48E, as amended by subsection (c), is amended—

(1) by redesignating subsection (j) as subsection (k), and

(2) by inserting after subsection (i) the following new subsection:

"(j) APPLICATION TO QUALIFIED FUEL CELL PROPERTY.—For purposes of this section, in the case of any qualified fuel cell property (as defined in section 48(c)(1), as applied without regard to subparagraph (E) thereof)—

"(1) subsection (b)(3)(A) shall be applied without regard to clause (iii) thereof,

"(2) for purposes of subsection (a)(1), the applicable percentage shall be 30 percent and such percentage shall not be increased or otherwise adjusted by any other provision of this section, and

"(3) subsection (g) shall not apply.".

(g) EFFECTIVE DATES.—

(1) IN GENERAL.—Except as provided in paragraphs (2), (3), (4), and (5), the amendments made by this section shall apply to taxable years beginning after the date of enactment of this Act.

(2) DOMESTIC CONTENT RULES.—The amendment made by subsection (d) shall apply on or after June 16, 2025.

(3) ELIMINATION OF ENERGY CREDIT FOR CERTAIN ENERGY PROPERTY.—The amendments made by subsection (e) shall apply to property the construction of which begins on or after June 16, 2025.

(4) APPLICATION OF CLEAN ELECTRICITY INVESTMENT CREDIT TO QUALIFIED FUEL CELL PROPERTY.—The amendments made by subsection (f) shall apply to property the construction of which begins after December 31, 2025.

(5) TERMINATION FOR WIND AND SOLAR FACILITIES.—The amendments made by subsection (a) shall apply to facilities the construction of which begins after the date which is 12 months after the date of enactment of this Act.

SEC. 70514. PHASE-OUT AND RESTRICTIONS ON ADVANCED MANUFACTURING PRODUCTION CREDIT.

(a) MODIFICATION OF PROVISION RELATING TO SALE OF INTEGRATED COMPONENTS.—Paragraph (4) of section 45X(d) is amended to read as follows:

"(4) SALE OF INTEGRATED COMPONENTS.—

"(A) IN GENERAL.—For purposes of this section, a person shall be treated as having sold an eligible component to an unrelated person if—

"(i) such component (referred to in this paragraph as the 'primary component') is integrated, incorporated, or assembled into another eligible component (referred to in this paragraph as the 'secondary component') produced within the same manufacturing facility as the primary component, and

"(ii) the secondary component is sold to an unrelated person.

"(B) ADDITIONAL REQUIREMENTS.—Subparagraph (A) shall only apply with respect to a secondary component for which not less than 65 percent of the total direct material costs which are paid or incurred (within the meaning of section 461 and any regulations issued under section 263A) by the taxpayer to produce such secondary component are attributable to primary components which are mined, produced, or manufactured in the United States.".

(b) PHASE OUT AND TERMINATION.—Section 45X(b)(3) is amended—

(1) in the heading, by inserting "AND TERMINATION" after "PHASE OUT",

(2) in subparagraph (A), in the matter preceding clause (i), by striking "subparagraph (C)" and inserting "subparagraphs (C) and (D)", and

(3) by striking subparagraph (C) and inserting the following:

"(C) PHASE OUT FOR APPLICABLE CRITICAL MINERALS OTHER THAN METALLURGICAL COAL.—

"(i) IN GENERAL.—In the case of any applicable critical mineral (other than metallurgical coal) produced after December 31, 2030, the amount determined under this subsection with respect to such mineral shall be equal to the product of—

"(I) the amount determined under paragraph (1) with respect to such mineral, as determined without regard to this subparagraph, multiplied by

"(II) the phase out percentage under clause (ii).

"(ii) PHASE OUT PERCENTAGE FOR APPLICABLE CRITICAL MINERALS OTHER THAN METALLURGICAL COAL.—The phase out percentage under this clause is equal to—

"(I) in the case of any applicable critical mineral produced during calendar year 2031, 75 percent,

"(II) in the case of any applicable critical mineral produced during calendar year 2032, 50 percent,

"(III) in the case of any applicable critical mineral produced during calendar year 2033, 25 percent, and

"(IV) in the case of any applicable critical mineral produced after December 31, 2033, 0 percent.

"(D) TERMINATION FOR WIND ENERGY COMPONENTS.—This section shall not apply to any wind energy component produced and sold after December 31, 2027.

"(E) TERMINATION FOR METALLURGICAL COAL.—This section shall not apply to any metallurgical coal produced after December 31, 2029.".

(c) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—Section 45X is amended—

(1) in subsection (c)(1), by adding at the end the following new subparagraph:

"(C) MATERIAL ASSISTANCE FROM PROHIBITED FOREIGN ENTITIES.—In the case of taxable years beginning after the date of enactment of this subparagraph, the term 'eligible component' shall not include any property which includes any material assistance from a prohibited foreign entity (as defined in section 7701(a)(52), as applied by substituting 'used in a product sold before January 1, 2027' for 'used in a product sold before January 1, 2030' in subparagraph (D)(iv)(II)(bb) thereof).", and

(2) in subsection (d), as amended by subsection (a) of this section, by adding at the end the following new paragraph:

"(4) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—No credit shall be determined under subsection (a) for any taxable year if the taxpayer is—

"(i) a specified foreign entity (as defined in section 7701(a)(51)(B)), or

"(ii) a foreign-influenced entity (as defined in section 7701(a)(51)(D), without regard to clause (i)(II) thereof).

"(B) EFFECTIVE CONTROL.—In the case of a taxpayer for which section 7701(a)(51)(D)(i)(II) is determined to apply for any taxable year, no credit shall be determined under subsection (a) for such taxable year if such determination relates to an eligible component described in subsection (c)(1).".

(d) MODIFICATION OF DEFINITION OF BATTERY MODULE.—Section 45X(c)(5)(B)(iii) is amended—

(1) in subclause (I)(bb), by striking "and" at the end,

(2) in subclause (II), by striking the period at the end and inserting ", and", and

(3) by adding at the end the following new subclause:

"(III) which is comprised of all other essential equipment needed for battery functionality, such as current collector assemblies and voltage sense harnesses, or any other essential energy collection equipment.".

(e) INCLUSION OF METALLURGICAL COAL AS AN APPLICABLE CRITICAL MINERAL FOR PURPOSES OF THE ADVANCED MANUFACTURING PRODUCTION CREDIT.—

(1) IN GENERAL.—Section 45X(c)(6) is amended—

(A) by redesignating subparagraphs (R) through (Z) as subparagraphs (S) through (AA), respectively, and

(B) by inserting after subparagraph (Q) the following new subparagraph:

"(R) METALLURGICAL COAL.—Metallurgical coal which is suitable for use in the production of steel (within the meaning of the notice published by the Department of Energy entitled 'Critical Material List; Addition of Metallurgical Coal Used for Steelmaking' (90 Fed. Reg. 22711 (May 29, 2025))), regardless of whether such production occurs inside or outside of the United States.".

(2) CREDIT AMOUNT.—Section 45X(b)(1)(M) is amended by inserting "(2.5 percent in the case of metallurgical coal)" after "10 percent".

(f) EFFECTIVE DATES.—

(1) IN GENERAL.—Except as provided in paragraph (2), the amendments made by this section shall apply to taxable years beginning after the date of enactment of this Act.

(2) MODIFICATION OF PROVISION RELATING TO SALE OF INTEGRATED COMPONENTS.—The amendment made by subsection (a) shall apply to components sold during taxable years beginning after December 31, 2026.

SEC. 70515. RESTRICTION ON THE EXTENSION OF ADVANCED ENERGY PROJECT CREDIT PROGRAM.

(a) IN GENERAL.—Section 48C(e)(3)(C) is amended by striking "shall be increased" and inserting "shall not be increased".

(b) EFFECTIVE DATE.—The amendment made by this section shall take effect on the date of enactment of this Act.

Subchapter B—Enhancement of America-first Energy Policy

SEC. 70521. EXTENSION AND MODIFICATION OF CLEAN FUEL PRODUCTION CREDIT.

(a) PROHIBITION ON FOREIGN FEEDSTOCKS.—

(1) IN GENERAL.—Section 45Z(f)(1)(A) is amended—

(A) in clause (i)(II)(bb), by striking "and" at the end,

(B) in clause (ii), by striking the period at the end and inserting ", and", and

(C) by adding at the end the following new clause:

"(iii) such fuel is exclusively derived from a feedstock which was produced or grown in the United States, Mexico, or Canada.".

(2) EFFECTIVE DATE.—The amendments made by this subsection shall apply to transportation fuel produced after December 31, 2025.

(b) PROHIBITION ON NEGATIVE EMISSION RATES.—

(1) IN GENERAL.—Section 45Z(b)(1) is amended—

(A) by striking subparagraph (C) and inserting the following:

"(C) ROUNDING OF EMISSIONS RATE.—The Secretary may round the emissions rates under subparagraph (B) to the nearest multiple of 5 kilograms of CO2e per mmBTU.", and

(B) by adding at the end the following new subparagraph:

"(E) PROHIBITION ON NEGATIVE EMISSION RATES.—For purposes of this section, the emissions rate for a transportation fuel may not be less than zero.".

(2) EFFECTIVE DATE.—The amendments made by this subsection shall apply to emissions rates published for transportation fuel produced after December 31, 2025.

(c) DETERMINATION OF EMISSIONS RATE.—

(1) IN GENERAL.—Section 45Z(b)(1)(B) is amended by adding at the end the following new clauses:

"(iv) EXCLUSION OF INDIRECT LAND USE CHANGES.—Notwithstanding clauses (i), (ii), and (iii), the emissions rate shall be adjusted as necessary to exclude any emissions attributed to indirect land use change. Any such adjustment shall be based on regulations or methodologies determined by the Secretary.

"(v) ANIMAL MANURES.—With respect to any transportation fuel which is derived from animal manure, the Secretary—

"(I) shall provide a distinct emissions rate with respect to such fuel based on the specific animal manure feedstock, which may include dairy manure, swine manure, poultry manure, or any other sources as are determined appropriate by the Secretary, and

"(II) notwithstanding subparagraph (E), may provide an emissions rate that is less than zero.".

(2) CONFORMING AMENDMENT.—Section 45Z(b)(1)(B)(i) is amended by striking "clauses (ii) and (iii)" and inserting "clauses (ii), (iii), (iv), and (v)".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall apply to emissions rates published for transportation fuel produced after December 31, 2025.

(d) EXTENSION OF CLEAN FUEL PRODUCTION CREDIT.—Section 45Z(g) is amended by striking "December 31, 2027" and inserting "December 31, 2029".

(e) PREVENTING DOUBLE CREDIT.—Section 45Z(d)(5) is amended—

(1) in subparagraph (A)—

(A) in clause (ii), by striking "and" at the end,

(B) in clause (iii), by striking the period at the end and inserting ", and", and

(C) by adding at the end the following new clause:

"(iv) is not produced from a fuel for which a credit under this section is allowable.", and

(2) by adding at the end the following new subparagraph:

"(C) REGULATIONS AND GUIDANCE.—The Secretary shall issue such regulations or other guidance as the Secretary determines necessary to carry out the purposes of subparagraph (A)(iv).".

(f) SALES TO UNRELATED PERSONS.—Section 45Z(f)(3) is amended by adding at the end the following: "The Secretary may prescribe additional related person rules similar to the rule described in the preceding sentence for entities which are not described in such sentence, including rules for related persons with respect to which the taxpayer has reason to believe will sell fuel to an unrelated person in a manner described in subsection (a)(4).".

(g) TREATMENT OF SUSTAINABLE AVIATION FUEL.—

(1) COORDINATION OF CREDITS.—

(A) IN GENERAL.—Section 6426(k) is amended by adding at the end the following new paragraph:

"(4) COORDINATION OF CREDITS.—With respect to any gallon of sustainable aviation fuel in a qualified mixture, this subsection shall not apply to any such gallon for which a credit under section 45Z is allowable (as determined without regard to subsection (a)(1)(A) of such section).".

(B) EFFECTIVE DATE.—The amendment made by this paragraph shall apply to—

(i) fuel sold or used on or after the date of the enactment of this Act, and

(ii) fuel sold or used before the date of enactment of this Act, but only to the extent that claims for the credit under section 6426(k) of the Internal Revenue Code of 1986 with respect to such sale or use have not been paid or allowed as of such date.

(2) ELIMINATION OF SPECIAL RATE.—

(A) IN GENERAL.—Paragraph (3) of section 45Z(a) is amended to read as follows:

"(3) DEFINITION OF SUSTAINABLE AVIATION FUEL.—For purposes of this section, the term 'sustainable aviation fuel' means liquid fuel, the portion of which is not kerosene, which is sold for use in an aircraft and which—

"(A) meets the requirements of—

"(i) ASTM International Standard D7566, or

"(ii) the Fischer Tropsch provisions of ASTM International Standard D1655, Annex A1, and

"(B) is not derived from palm fatty acid distillates or petroleum.".

(B) CONFORMING AMENDMENT.—Section 45Z(c)(1) is amended by striking ", the $1.00 amount in subsection (a)(2)(B), the 35 cent amount in subsection (a)(3)(A)(i), and the $1.75 amount in subsection (a)(3)(A)(ii)" and inserting "and the $1.00 amount in subsection (a)(2)(B)".

(C) EFFECTIVE DATE.—The amendments made by this paragraph shall apply to fuel produced after December 31, 2025.

(h) SUSTAINABLE AVIATION FUEL CREDIT.—Section 6426(k), as amended by the preceding provisions of this Act, is amended by adding at the end the following new paragraph:

"(5) TERMINATION.—This subsection shall not apply to any sale or use for any period after September 30, 2025.".

(i) REGISTRATION OF PRODUCERS OF FUEL ELIGIBLE FOR CLEAN FUEL PRODUCTION CREDIT.—

(1) IN GENERAL.—Section 13704(b)(5) of Public Law 117-169 is amended by striking "after 'section 6426(k)(3)),'" and inserting "after 'section 40B),'".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to transportation fuel produced after December 31, 2024.

(j) EXTENSION AND MODIFICATION OF SMALL AGRI-BIODIESEL PRODUCER CREDIT.—

(1) IN GENERAL.—Section 40A is amended—

(A) in subsection (b)(4)—

(i) in subparagraph (A), by striking "10 cents" and inserting "20 cents",

(ii) in subparagraph (B), by inserting "in a manner which complies with the requirements under section 45Z(f)(1)(A)(iii)" after "produced by an eligible small agri-biodiesel producer", and

(iii) by adding at the end the following new subparagraph:

"(D) COORDINATION WITH CLEAN FUEL PRODUCTION CREDIT.—The credit determined under this paragraph with respect to any gallon of fuel shall be in addition to any credit determined under section 45Z with respect to such gallon of fuel.", and

(B) in subsection (g), by inserting "(or, in the case of the small agri-biodiesel producer credit, any sale or use after December 31, 2026)" after "December 31, 2024".

(2) TRANSFER OF CREDIT.—Section 6418(f)(1)(A) is amended by adding at the end the following new clause:

"(xii) So much of the biodiesel fuels credit determined under section 40A which consists of the small agri-biodiesel producer credit determined under subsection (b)(4) of such section.".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall apply to fuel sold or used after June 30, 2025.

(k) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

(1) IN GENERAL.—Section 45Z(f) is amended by adding at the end the following new paragraph:

"(8) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—

"(A) IN GENERAL.—No credit shall be determined under subsection (a) for any taxable year beginning after the date of enactment of this paragraph if the taxpayer is a specified foreign entity (as defined in section 7701(a)(51)(B)).

"(B) OTHER PROHIBITED FOREIGN ENTITIES.—No credit shall be determined under subsection (a) for any taxable year beginning after the date which is 2 years after the date of enactment of this paragraph if the taxpayer is a foreign-influenced entity (as defined in section 7701(a)(51)(D), without regard to clause (i)(II) thereof).".

(2) EFFECTIVE DATE.—The amendment made by this subsection shall apply to taxable years beginning after the date of enactment of this Act.

SEC. 70522. RESTRICTIONS ON CARBON OXIDE SEQUESTRATION CREDIT.

(a) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—Section 45Q(f) is amended by adding at the end the following new paragraph:

"(10) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—No credit shall be determined under subsection (a) for any taxable year beginning after the date of enactment of this paragraph if the taxpayer is—

"(A) a specified foreign entity (as defined in section 7701(a)(51)(B)), or

"(B) a foreign-influenced entity (as defined in section 7701(a)(51)(D), determined without regard to clause (i)(II) thereof).".

(b) PARITY FOR DIFFERENT USES AND UTILIZATIONS OF QUALIFIED CARBON OXIDE.—Section 45Q is amended—

(1) in subsection (a)—

(A) in paragraph (2)(B)(ii), by adding "and" at the end,

(B) in paragraph (3), by striking subparagraph (B) and inserting the following:

"(B)(i) disposed of by the taxpayer in secure geological storage and not used by the taxpayer as described in clause (ii) or (iii),

"(ii) used by the taxpayer as a tertiary injectant in a qualified enhanced oil or natural gas recovery project and disposed of by the taxpayer in secure geological storage, or

"(iii) utilized by the taxpayer in a manner described in subsection (f)(5).", and

(C) by striking paragraph (4),

(2) in subsection (b)—

(A) in paragraph (1)—

(i) by striking subparagraph (A) and inserting the following:

"(A) IN GENERAL.—Except as provided in subparagraph (B) or (C), the applicable dollar amount shall be an amount equal to—

"(i) for any taxable year beginning in a calendar year after 2024 and before 2027, $17, and

"(ii) for any taxable year beginning in a calendar year after 2026, an amount equal to the product of $17 and the inflation adjustment factor for such calendar year determined under section 43(b)(3)(B) for such calendar year, determined by substituting '2025' for '1990'.", and

(ii) in subparagraph (B), by striking "shall be applied" and all that follows through the period and inserting "shall be applied by substituting '$36' for '$17' each place it appears.",

(B) in paragraph (2)(B), by striking "paragraphs (3)(A) and (4)(A)" and inserting "paragraph (3)(A)", and

(C) in paragraph (3), by striking "the dollar amounts applicable under paragraph (3) or (4)" and inserting "the dollar amount applicable under paragraph (3)",

(3) in subsection (f)—

(A) in paragraph (5)(B)(i), by striking "(4)(B)(ii)" and inserting "(3)(B)(iii)", and

(B) in paragraph (9), by striking "paragraphs (3) and (4) of subsection (a)" and inserting "subsection (a)(3)", and

(4) in subsection (h)(3)(A)(ii), by striking "paragraph (3)(A) or (4)(A) of subsection (a)" and inserting "subsection (a)(3)(A)".

(c) CONFORMING AMENDMENT.—Section 6417(d)(3)(C)(i)(II)(bb) is amended by striking "paragraph (3)(A) or (4)(A) of section 45Q(a)" and inserting "section 45Q(a)(3)(A)".

(d) EFFECTIVE DATES.—

(1) RESTRICTIONS RELATING TO PROHIBITED FOREIGN ENTITIES.—The amendment made by subsection (a) shall apply to taxable years beginning after the date of enactment of this Act.

(2) PARITY FOR DIFFERENT USES AND UTILIZATIONS OF QUALIFIED CARBON OXIDE.—The amendments made subsections (b) and (c) shall apply to facilities or equipment placed in service after the date of enactment of this Act.

SEC. 70523. INTANGIBLE DRILLING AND DEVELOPMENT COSTS TAKEN INTO ACCOUNT FOR PURPOSES OF COMPUTING ADJUSTED FINANCIAL STATEMENT INCOME.

(a) IN GENERAL.—Section 56A(c)(13) is amended—

(1) by striking subparagraph (A) and inserting the following:

"(A) reduced by—

"(i) depreciation deductions allowed under section 167 with respect to property to which section 168 applies to the extent of the amount allowed as deductions in computing taxable income for the year, and

"(ii) any deduction allowed for expenses under section 263(c) (including any deduction for such expenses under section 59(e) or 291(b)(2)) with respect to property described therein to the extent of the amount allowed as deductions in computing taxable income for the year, and", and

(2) by striking subparagraph (B)(i) and inserting the following:

"(i) to disregard any amount of—

"(I) depreciation expense that is taken into account on the taxpayer's applicable financial statement with respect to such property, and

"(II) depletion expense that is taken into account on the taxpayer's applicable financial statement with respect to the intangible drilling and development costs of such property, and".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70524. INCOME FROM HYDROGEN STORAGE, CARBON CAPTURE, ADVANCED NUCLEAR, HYDROPOWER, AND GEOTHERMAL ENERGY ADDED TO QUALIFYING INCOME OF CERTAIN PUBLICLY TRADED PARTNERSHIPS.

(a) IN GENERAL.—Section 7704(d)(1)(E) is amended—

(1) by striking "income and gains derived from the exploration" and inserting the following: "income and gains derived from—

"(i) the exploration".

(2) by inserting "or" before "industrial source", and

(3) by striking "or the transportation or storage" and all that follows and inserting the following:

"(ii) the transportation or storage of—

"(I) any fuel described in subsection (b), (c), (d), (e), or (k) of section 6426, or any alcohol fuel defined in section 6426(b)(4)(A) or any biodiesel fuel as defined in section 40A(d)(1) or sustainable aviation fuel as defined in section 40B(d)(1), or

"(II) liquified hydrogen or compressed hydrogen,

"(iii) in the case of a qualified facility (as defined in section 45Q(d), without regard to any date by which construction of the facility or equipment is required to begin) not less than 50 percent of the total carbon oxide production of which is qualified carbon oxide (as defined in section 45Q(c))—

"(I) the generation, availability for such generation, or storage of electric power at such facility, or

"(II) the capture of carbon dioxide by such facility,

"(iv) the production of electricity from any advanced nuclear facility (as defined in section 45J(d)(2)),

"(v) the production of electricity or thermal energy exclusively using a qualified energy resource described in subparagraph (D) or (H) of section 45(c)(1), or

"(vi) the operation of energy property described in clause (iii) or (vii) of section 48(a)(3)(A) (determined without regard to any requirement under such section with respect to the date on which construction of property begins).".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70525. ALLOW FOR PAYMENTS TO CERTAIN INDIVIDUALS WHO DYE FUEL.

(a) IN GENERAL.—Subchapter B of chapter 65, as amended by the preceding provisions of this Act, is amended by adding at the end the following new section:

"SEC. 6435. DYED FUEL.

"(a) IN GENERAL.—If a person establishes to the satisfaction of the Secretary that such person meets the requirements of subsection (b) with respect to diesel fuel or kerosene, then the Secretary shall pay to such person an amount (without interest) equal to the tax described in subsection (b)(2)(A) with respect to such diesel fuel or kerosene.

"(b) REQUIREMENTS.—

"(1) IN GENERAL.—A person meets the requirements of this subsection with respect to diesel fuel or kerosene if such person removes from a terminal eligible indelibly dyed diesel fuel or kerosene.

"(2) ELIGIBLE INDELIBLY DYED DIESEL FUEL OR KEROSENE DEFINED.—The term 'eligible indelibly dyed diesel fuel or kerosene' means diesel fuel or kerosene—

"(A) with respect to which a tax under section 4081 was previously paid (and not credited or refunded), and

"(B) which is exempt from taxation under section 4082(a).

"(c) CROSS REFERENCE.—For civil penalty for excessive claims under this section, see section 6675.".

(b) CONFORMING AMENDMENTS.—

(1) Section 6206 is amended—

(A) by striking "or 6427" each place it appears and inserting "6427, or 6435", and

(B) by striking "6420 and 6421" and inserting "6420, 6421, and 6435".

(2) Section 6430 is amended—

(A) by striking "or" at the end of paragraph (2), by striking the period at the end of paragraph (3) and inserting ", or", and by adding at the end the following new paragraph:

"(4) which are removed as eligible indelibly dyed diesel fuel or kerosene under section 6435.".

(3) Section 6675 is amended—

(A) in subsection (a), by striking "or 6427 (relating to fuels not used for taxable purposes)" and inserting "6427 (relating to fuels not used for taxable purposes), or 6435 (relating to eligible indelibly dyed fuel)", and

(B) in subsection (b)(1), by striking "6421, or 6427," and inserting "6421, 6427, or 6435,".

(4) The table of sections for subchapter B of chapter 65, as amended by the preceding provisions of this Act, is amended by adding at the end the following new item:

"Sec. 6435. Dyed fuel.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to eligible indelibly dyed diesel fuel or kerosene removed on or after the date that is 180 days after the date of the enactment of this section.

Subchapter C—Other Reforms

SEC. 70531. MODIFICATIONS TO DE MINIMIS ENTRY PRIVILEGE FOR COMMERCIAL SHIPMENTS.

(a) CIVIL PENALTY.—

(1) ADDITIONAL PENALTY IMPOSED.—Section 321 of the Tariff Act of 1930 (19 U.S.C. 1321) is amended by adding at the end the following new subsection:

"(c) Any person who enters, introduces, facilitates, or attempts to introduce an article into the United States using the privilege of this section, the importation of which violates any other provision of United States customs law, shall be assessed, in addition to any other penalty permitted by law, a civil penalty of up to $5,000 for the first violation and up to $10,000 for each subsequent violation.".

(2) EFFECTIVE DATE.—The amendment made by paragraph (1) shall take effect 30 days after the date of the enactment of this Act.

(b) REPEAL OF COMMERCIAL SHIPMENT EXCEPTION.—

(1) REPEAL.—Section 321(a)(2) of such Act (19 U.S.C. 1321(a)(2)) is amended by striking "of this Act, or" and all that follows through "subdivision (2); and" and inserting "of this Act; and".

(2) CONFORMING REPEAL.—Subsection (c) of such section 321, as added by subsection (a) of this section, is repealed.

(3) EFFECTIVE DATE.—The amendments made by this subsection shall take effect on July 1, 2027.

CHAPTER 6—ENHANCING DEDUCTION AND INCOME TAX CREDIT GUARDRAILS, AND OTHER REFORMS

SEC. 70601. MODIFICATION AND EXTENSION OF LIMITATION ON EXCESS BUSINESS LOSSES OF NONCORPORATE TAXPAYERS.

(a) RULE MADE PERMANENT.—Section 461(l)(1) is amended by striking "and before January 1, 2029," each place it appears.

(b) ADJUSTMENT OF AMOUNTS FOR CALCULATION OF EXCESS BUSINESS LOSS.—Section 461(l)(3)(C) is amended—

(1) in the matter preceding clause (i), by striking "December 31, 2018" and inserting "December 31, 2025", and

(2) in clause (ii), by striking "2017" and inserting "2024".

(c) EFFECTIVE DATES.—

(1) RULE MADE PERMANENT.—The amendments made by subsection (a) shall apply to taxable years beginning after December 31, 2026.

(2) ADJUSTMENT OF AMOUNTS FOR CALCULATION OF EXCESS BUSINESS LOSS.—The amendments made by subsection (b) shall apply to taxable years beginning after December 31, 2025.

SEC. 70602. TREATMENT OF PAYMENTS FROM PARTNERSHIPS TO PARTNERS FOR PROPERTY OR SERVICES.

(a) IN GENERAL.—Section 707(a)(2) is amended by striking "Under regulations prescribed" and inserting "Except as provided".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to services performed, and property transferred, after the date of the enactment of this Act.

(c) RULE OF CONSTRUCTION.—Nothing in this section, or the amendments made by this section, shall be construed to create any inference with respect to the proper treatment under section 707(a) of the Internal Revenue Code of 1986 with respect to payments from a partnership to a partner for services performed, or property transferred, on or before the date of the enactment of this Act.

SEC. 70603. EXCESSIVE EMPLOYEE REMUNERATION FROM CONTROLLED GROUP MEMBERS AND ALLOCATION OF DEDUCTION.

(a) APPLICATION OF AGGREGATION RULES.—Section 162(m) is amended by adding at the end the following new paragraph:

"(7) REMUNERATION FROM CONTROLLED GROUP MEMBERS.—

"(A) IN GENERAL.—In the case of any publicly held corporation which is a member of a controlled group—

"(i) paragraph (1) shall be applied by substituting 'specified covered employee' for 'covered employee', and

"(ii) if any person which is a member of such controlled group (other than such publicly held corporation) provides applicable employee remuneration to an individual who is a specified covered employee of such controlled group and the aggregate amount described in subparagraph (B)(ii) with respect to such specified covered employee exceeds $1,000,000—

"(I) paragraph (1) shall apply to such person with respect to such remuneration, and

"(II) paragraph (1) shall apply to such publicly held corporation and to each such related person by substituting 'the allocable limitation amount' for '$1,000,000'.

"(B) ALLOCABLE LIMITATION AMOUNT.—For purposes of this paragraph, the term 'allocable limitation amount' means, with respect to any member of the controlled group referred to in subparagraph (A) with respect to any specified covered employee of such controlled group, the amount which bears the same ratio to $1,000,000 as—

"(i) the amount of applicable employee remuneration provided by such member with respect to such specified covered employee, bears to "(ii) the aggregate amount of applicable employee remuneration provided by all such members with respect to such specified covered employee.

"(C) SPECIFIED COVERED EMPLOYEE.—For purposes of this paragraph, the term 'specified covered employee' means, with respect to any controlled group—

"(i) any employee described in subparagraph (A), (B), or (D) of paragraph (3), with respect to the publicly held corporation which is a member of such controlled group, and

"(ii) any employee who would be described in subparagraph (C) of paragraph (3) if such subparagraph were applied by taking into account the employees of all members of the controlled group.

"(D) CONTROLLED GROUP.—For purposes of this paragraph, the term 'controlled group' means any group treated as a single employer under subsection (b), (c), (m), or (o) of section 414.".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70604. EXCISE TAX ON CERTAIN REMITTANCE TRANSFERS.

(a) IN GENERAL.—Chapter 36 is amended by inserting after subchapter B the following new subchapter:

"Subchapter C—Remittance Transfers

"SEC. 4475. IMPOSITION OF TAX.

"(a) IN GENERAL.—There is hereby imposed on any remittance transfer a tax equal to 1 percent of the amount of such transfer.

"(b) PAYMENT OF TAX.—

"(1) IN GENERAL.—The tax imposed by this section with respect to any remittance transfer shall be paid by the sender with respect to such transfer.

"(2) COLLECTION OF TAX.—The remittance transfer provider with respect to any remittance transfer shall collect the amount of the tax imposed under subsection (a) with respect to such transfer from the sender and remit such tax quarterly to the Secretary at such time and in such manner as provided by the Secretary,

"(3) SECONDARY LIABILITY.—Where any tax imposed by subsection (a) is not paid at the time the transfer is made, then to the extent that such tax is not collected, such tax shall be paid by the remittance transfer provider.

"(c) TAX LIMITED TO CASH AND SIMILAR INSTRUMENTS.—The tax imposed under subsection (a) shall apply only to any remittance transfer for which the sender provides cash, a money order, a cashier's check, or any other similar physical instrument (as determined by the Secretary) to the remittance transfer provider.

"(d) NONAPPLICATION TO CERTAIN NONCASH REMITTANCE TRANSFERS.—Subsection (a) shall not apply to any remittance transfer for which the funds being transferred are—

"(1) withdrawn from an account held in or by a financial institution—

"(A) which is described in subparagraphs (A) through (H) of section 5312(a)(2) of title 31, United States Code, and

"(B) that is subject to the requirements under subchapter II of chapter 53 of such title, or

"(2) funded with a debit card or a credit card which is issued in the United States.

"(e) DEFINITIONS.—For purposes of this section—

"(1) IN GENERAL.—The terms 'remittance transfer', 'remittance transfer provider', and 'sender' shall each have the respective meanings given such terms by section 919(g) of the Electronic Fund Transfer Act (15 U.S.C. 1693o–1(g)).

"(2) CREDIT CARD.—The term 'credit card' has the same meaning given such term under section 920(c)(3) of the Electronic Fund Transfer Act (15 U.S.C. 1693o–2(c)(3)).

"(3) DEBIT CARD.—The term 'debit card' has the same meaning given such term under section 920(c)(2) of the Electronic Fund Transfer Act (15 U.S.C. 1693o–2(c)(2)), without regard to subparagraph (B) of such section.

"(f) APPLICATION OF ANTI-CONDUIT RULES.—For purposes of section 7701(l), with respect to any multiple-party arrangements involving the sender, a remittance transfer shall be treated as a financing transaction.".

(b) CONFORMING AMENDMENT.—The table of subchapters for chapter 36 is amended by inserting after the item relating to subchapter B the following new item:

"SUBCHAPTER C—REMITTANCE TRANSFERS".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to transfers made after December 31, 2025.

SEC. 70605. ENFORCEMENT PROVISIONS WITH RESPECT TO COVID-RELATED EMPLOYEE RETENTION CREDITS.

(a) ASSESSABLE PENALTY FOR FAILURE TO COMPLY WITH DUE DILIGENCE REQUIREMENTS.—

(1) IN GENERAL.—Any COVID–ERTC promoter which provides aid, assistance, or advice with respect to any COVID–ERTC document and which fails to comply with due diligence requirements imposed by the Secretary with respect to determining eligibility for, or the amount of, any credit or advance payment of a credit under section 3134 of the Internal Revenue Code of 1986, shall pay a penalty of $1,000 for each such failure.

(2) DUE DILIGENCE REQUIREMENTS.—The due diligence requirements referred to in paragraph (1) shall be similar to the due diligence requirements imposed under section 6695(g) of the Internal Revenue Code of 1986.

(3) RESTRICTION TO DOCUMENTS USED IN CONNECTION WITH RETURNS OR CLAIMS FOR REFUND.—Paragraph (1) shall not apply with respect to any COVID–ERTC document unless such document constitutes, or relates to, a return or claim for refund.

(4) TREATMENT AS ASSESSABLE PENALTY, ETC.—For purposes of the Internal Revenue Code of 1986, the penalty imposed under paragraph (1) shall be treated as a penalty which is imposed under section 6695(g) of such Code and assessed under section 6201 of such Code.

(5) SECRETARY.—For purposes of this subsection, the term "Secretary" means the Secretary of the Treasury or the Secretary's delegate.

(b) COVID–ERTC PROMOTER.—For purposes of this section—

(1) IN GENERAL.—The term "COVID–ERTC promoter" means, with respect to any COVID–ERTC document, any person which provides aid, assistance, or advice with respect to such document if—

(A) such person charges or receives a fee for such aid, assistance, or advice which is based on the amount of the refund or credit with respect to such document and, with respect to such person's taxable year in which such person provided such assistance or the preceding taxable year, the aggregate of the gross receipts of such person for aid, assistance, and advice with respect to all COVID-ERTC documents exceeds 20 percent of the gross receipts of such person for such taxable year, or

(B) with respect to such person's taxable year in which such person provided such assistance or the preceding taxable year—

(i) the aggregate of the gross receipts of such person for aid, assistance, and advice with respect to all COVID–ERTC documents exceeds 50 percent of the gross receipts of such person for such taxable year, or

(ii) both—

(I) such aggregate gross receipts exceed 20 percent of the gross receipts of such person for such taxable year, and

(II) the aggregate of the gross receipts of such person for aid, assistance, and advice with respect to all COVID–ERTC documents (determined after application of paragraph (3)) exceeds $500,000.

(2) EXCEPTION FOR CERTIFIED PROFESSIONAL EMPLOYER ORGANIZATIONS.—The term "COVID–ERTC promoter" shall not include a certified professional employer organization (as defined in section 7705 of the Internal Revenue Code of 1986).

(3) AGGREGATION RULE.—For purposes of paragraph (1), all persons treated as a single employer under subsection (a) or (b) of section 52 of the Internal Revenue Code of 1986, or subsection (m) or (o) of section 414 of such Code, shall be treated as 1 person.

(4) SHORT TAXABLE YEARS.—In the case of any taxable year of less than 12 months, a person shall be treated as a COVID-ERTC promoter if such person is described in paragraph (1) either with respect to such taxable year or by treating any reference to such taxable year as a reference to the calendar year in which such taxable year begins.

(c) COVID–ERTC DOCUMENT.—For purposes of this section, the term "COVID–ERTC document" means any return, affidavit, claim, or other document related to any credit or advance payment of a credit under section 3134 of the Internal Revenue Code of 1986, including any document related to eligibility for, or the calculation or determination of any amount directly related to, any such credit or advance payment.

(d) LIMITATION ON CREDITS AND REFUNDS.—Notwithstanding section 6511 of the Internal Revenue Code of 1986, no credit under section 3134 of the Internal Revenue Code of 1986 shall be allowed, and no refund with respect to any such credit shall be made, after the date of the enactment of this Act, unless a claim for such credit or refund was filed by the taxpayer on or before January 31, 2024.

(e) EXTENSION OF LIMITATION ON ASSESSMENT.—Section 3134(l) is amended to read as follows:

"(l) EXTENSION OF LIMITATION ON ASSESSMENT.—

"(1) IN GENERAL.—Notwithstanding section 6501, the limitation on the time period for the assessment of any amount attributable to a credit claimed under this section shall not expire before the date that is 6 years after the latest of—

"(A) the date on which the original return which includes the calendar quarter with respect to which such credit is determined is filed,

"(B) the date on which such return is treated as filed under section 6501(b)(2), or

"(C) the date on which the claim for credit or refund with respect to such credit is made.

"(2) DEDUCTION FOR WAGES TAKEN INTO ACCOUNT IN DETERMINING IMPROPERLY CLAIMED CREDIT.—

"(A) IN GENERAL.—Notwithstanding section 6511, in the case of an assessment attributable to a credit claimed under this section, the limitation on the time period for credit or refund of any amount attributable to a deduction for improperly claimed ERTC wages shall not expire before the time period for such assessment expires under paragraph (1).

"(B) IMPROPERLY CLAIMED ERTC WAGES.—For purposes of this paragraph, the term 'improperly claimed ERTC wages' means, with respect to an assessment attributable to a credit claimed under this section, the wages with respect to which a deduction would not have been allowed if the portion of the credit to which such assessment relates had been properly claimed.".

(f) AMENDMENT TO PENALTY FOR ERRONEOUS CLAIM FOR REFUND OR CREDIT.—Section 6676(a) is amended by striking "income tax" and inserting "income or employment tax".

(g) EFFECTIVE DATES.—

(1) IN GENERAL.—The provisions of this section shall apply to aid, assistance, and advice provided after the date of the enactment of this Act.

(2) LIMITATION ON CREDITS AND REFUNDS.—Subsection (d) shall apply to credits and refunds allowed or made after the date of the enactment of this Act.

(3) EXTENSION OF LIMITATION ON ASSESSMENT.—The amendment made by subsection (e) shall apply to assessments made after the date of the enactment of this Act.

(4) AMENDMENT TO PENALTY FOR ERRONEOUS CLAIM FOR REFUND OR CREDIT.—The amendment made by subsection (f) shall apply to claims for credit or refund after the date of the enactment of this Act.

(h) REGULATIONS.—The Secretary (as defined in subsection (a)(5)) shall issue such regulations or other guidance as may be necessary or appropriate to carry out the purposes of this section (and the amendments made by this section).

SEC. 70606. SOCIAL SECURITY NUMBER REQUIREMENT FOR AMERICAN OPPORTUNITY AND LIFETIME LEARNING CREDITS.

(a) SOCIAL SECURITY NUMBER OF TAXPAYER REQUIRED.—Section 25A(g)(1) is amended to read as follows:

"(1) IDENTIFICATION REQUIREMENT.—

"(A) SOCIAL SECURITY NUMBER REQUIREMENT.—No credit shall be allowed under subsection (a) to an individual unless the individual includes on the return of tax for the taxable year—

"(i) such individual's social security number, and

"(ii) in the case of a credit with respect to the qualified tuition and related expenses of an individual other than the taxpayer or the taxpayer's spouse, the name and social security number of such individual.

"(B) INSTITUTION.—No American Opportunity Tax Credit shall be allowed under this section unless the taxpayer includes the employer identification number of any institution to which the taxpayer paid qualified tuition and related expenses taken into account under this section on the return of tax for the taxable year.

"(C) SOCIAL SECURITY NUMBER DEFINED.—For purposes of this paragraph, the term 'social security number' shall have the meaning given such term in section 24(h)(7).".

(b) OMISSION TREATED AS MATHEMATICAL OR CLERICAL ERROR.—Section 6213(g)(2)(J) is amended by striking "TIN" and inserting "social security number or employer identification number".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

SEC. 70607. TASK FORCE ON THE REPLACEMENT OF DIRECT FILE.

Out of any money in the Treasury not otherwise appropriated, there is hereby appropriated for the fiscal year ending September 30, 2026, $15,000,000, to remain available until September 30, 2026, for necessary expenses of the Department of the Treasury to deliver to Congress, within 90 days following the date of the enactment of this Act, a report on—

(1) the cost of enhancing and establishing public-private partnerships which provide for free tax filing for up to 70 percent of all taxpayers calculated by adjusted gross income, and to replace any direct e-file programs run by the Internal Revenue Service;

(2) taxpayer opinions and preferences regarding a taxpayer-funded, government-run service or a free service provided by the private sector;

(3) assessment of the feasibility of a new approach, how to make the options consistent and simple for taxpayers across all participating providers, and how to provide features to address taxpayer needs; and

(4) the cost (including options for differential coverage based on taxpayer adjusted gross income and return complexity) of developing and running a free direct e-file tax return system, including costs to build and administer each release.

Subtitle B—Health

CHAPTER 1—MEDICAID

Subchapter A—Reducing Fraud and Improving Enrollment Processes

SEC. 71101. MORATORIUM ON IMPLEMENTATION OF RULE RELATING TO ELIGIBILITY AND ENROLLMENT IN MEDICARE SAVINGS PROGRAMS.

(a) IN GENERAL.—The Secretary of Health and Human Services shall not, during the period beginning on the date of the enactment of this section and ending September 30, 2034, implement, administer, or enforce the amendments made by the provisions of the final rule published by the Centers for Medicare & Medicaid Services on September 21, 2023, and titled "Streamlining Medicaid; Medicare Savings Program Eligibility Determination and Enrollment" (88 Fed. Reg. 65230) to the following sections of title 42, Code of Federal Regulations:

(1) Section 406.21(c).
(2) Section 435.4.
(3) Section 435.601.
(4) Section 435.911.
(5) Section 435.952.

(b) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of this section and section 71102, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $1,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71102. MORATORIUM ON IMPLEMENTATION OF RULE RELATING TO ELIGIBILITY AND ENROLLMENT FOR MEDICAID, CHIP, AND THE BASIC HEALTH PROGRAM.

The Secretary of Health and Human Services shall not, during the period beginning on the date of the enactment of this section and ending September 30, 2034, implement, administer, or enforce the amendments made by the provisions of the final rule published by the Centers for Medicare & Medicaid Services on April 2, 2024, and titled "Medicaid Program; Streamlining the Medicaid, Children's Health Insurance Program, and Basic Health Program Application, Eligibility Determination, Enrollment, and Renewal Processes" (89 Fed. Reg. 22780) to the following sections of title 42, Code of Federal Regulations:

(1) PART 431.—
(A) Section 431.213(d).
(2) PART 435.—
(A) Section 435.222.
(B) Section 435.407.
(C) Section 435.907.
(D) Section 435.911(c).
(E) Section 435.912.
(F) Section 435.916.
(G) Section 435.919.
(H) Section 435.1200(b)(3)(i)-(v).
(I) Section 435.1200(e)(1)(ii).
(J) Section 435.1200(h)(1).

(3) PART 447.—Section 447.56(a)(1)(v).

(4) PART 457.—

(A) Section 457.344.

(B) Section 457.960.

(C) Section 457.1140(d)(4).

(D) Section 457.1170.

(E) Section 457.1180.

SEC. 71103. REDUCING DUPLICATE ENROLLMENT UNDER THE MEDICAID AND CHIP PROGRAMS.

(a) MEDICAID.—

(1) IN GENERAL.—Section 1902 of the Social Security Act (42 U.S.C. 1396a) is amended—

(A) in subsection (a)—

(i) in paragraph (86), by striking "and" at the end;

(ii) in paragraph (87), by striking the period and inserting "; and"; and

(iii) by inserting after paragraph (87) the following new paragraph:

"(88) provide—

"(A) beginning not later than January 1, 2027, in the case of 1 of the 50 States and the District of Columbia, for a process to regularly obtain address information for individuals enrolled under such plan (or a waiver of such plan) in accordance with subsection (vv); and

"(B) beginning not later than October 1, 2029—

"(i) for the State to submit to the system established by the Secretary under subsection (uu), with respect to an individual enrolled or seeking to enroll under such plan, not less frequently than once each month and during each determination or redetermination of the eligibility of such individual for medical assistance under such plan (or waiver of such plan)—

"(I) the social security number of such individual, if such individual has a social security number and is required to provide such number to enroll under such plan (or waiver); and

"(II) such other information with respect to such individual as determined necessary by the Secretary for purposes of preventing individuals from simultaneously being enrolled under State plans (or waivers of such plans) of multiple States;

"(ii) for the use of such system to prevent such simultaneous enrollment; and

"(iii) in the case that such system indicates that an individual enrolled or seeking to enroll under such plan (or waiver of such plan) is enrolled under a State plan (or waiver of such a plan) of another State, for the taking of appropriate action (as determined by the Secretary) to identify whether such an individual resides in the State and disenroll an individual from the State plan of such State if such individual does not reside in such State (unless such individual meets such an exception as the Secretary may specify)."; and

(B) by adding at the end the following new subsections:

"(uu) PREVENTION OF ENROLLMENT UNDER MULTIPLE STATE PLANS.—

"(1) IN GENERAL.—Not later than October 1, 2029, the Secretary shall establish a system to be utilized by the Secretary and States to prevent an individual from being simultaneously enrolled under the State plans (or waivers of such plans) of multiple States. Such system shall—

"(A) provide for the receipt of information submitted by a State under subsection (a)(88)(B)(i); and

"(B) not less than once each month, transmit information to a State (or allow the Secretary to transmit information to a State) regarding whether an individual enrolled or seeking to enroll under the State plan of such State (or waiver of such plan) is enrolled under the State plan (or waiver of such plan) of another State.

"(2) STANDARDS.—The Secretary shall establish such standards as determined necessary by the Secretary to limit and protect information submitted under such system and ensure the privacy of such information, consistent with subsection (a)(7).

"(3) IMPLEMENTATION FUNDING.—There are appropriated to the Administrator of the Centers for Medicare & Medicaid Services, out of amounts in the Treasury not otherwise appropriated, in addition to amounts otherwise available—

"(A) for fiscal year 2026, $10,000,000 for purposes of establishing the system and standards required under this subsection, to remain available until expended; and

"(B) for fiscal year 2029, $20,000,000 for purposes of maintaining such system, to remain available until expended.

"(vv) PROCESS TO OBTAIN ENROLLEE ADDRESS INFORMATION.—

"(1) IN GENERAL.—For purposes of subsection (a)(88)(A), a process to regularly obtain address information for individuals enrolled under a State plan (or a waiver of such plan) shall obtain address information from reliable data sources described in paragraph (2) and take such actions as the Secretary shall specify with respect to any changes to such address based on such information.

"(2) RELIABLE DATA SOURCES DESCRIBED.—For purposes of paragraph (1), the reliable data sources described in this paragraph are the following:

"(A) Mail returned to the State by the United States Postal Service with a forwarding address.

"(B) The National Change of Address Database maintained by the United States Postal Service.

"(C) A managed care entity (as defined in section 1932(a)(1)(B)) or prepaid inpatient health plan or prepaid ambulatory health plan (as such terms are defined in section 1903(m)(9)(D)) that has a contract under the State plan if the address information is provided to such entity or plan directly from, or verified by such entity or plan directly with, such individual.

"(D) Other data sources as identified by the State and approved by the Secretary.".

(2) CONFORMING AMENDMENTS.—

(A) PARIS.—Section 1903(r)(3) of the Social Security Act (42 U.S.C. 1396b(r)(3)) is amended—

(i) by striking "In order" and inserting "(A) In order";

(ii) by striking "through the Public" and inserting "through—

"(i) the Public";

(iii) by striking the period at the end and inserting "; and

"(ii) beginning October 1, 2029, the system established by the Secretary under section 1902(uu)."; and

(iv) by adding at the end the following new subparagraph:

"(B) Beginning October 1, 2029, the Secretary may determine that a State is not required to have in operation an eligibility determination system which provides for data matching (for purposes of address verification under section 1902(vv)) through the system described in subparagraph (A)(i) to meet the requirements of this paragraph.".

(B) MANAGED CARE.—Section 1932 of the Social Security Act (42 U.S.C. 1396u–2) is amended by adding at the end the following new subsection:

"(j) TRANSMISSION OF ADDRESS INFORMATION.—Beginning January 1, 2027, each contract under a State plan with a managed care entity (as defined in section 1932(a)(1)(B)) or with a prepaid inpatient health plan or prepaid ambulatory health plan (as such terms are defined in section 1903(m)(9)(D)), shall provide that such entity or plan shall promptly transmit to the State any address information for an individual enrolled with such entity or plan that is provided to such entity or plan directly from, or verified by such entity or plan directly with, such individual.".

(b) CHIP.—

(1) IN GENERAL.—Section 2107(e)(1) of the Social Security Act (42 U.S.C. 1397gg(e)(1)) is amended—

(A) by redesignating subparagraphs (H) through (U) as subparagraphs (I) through (V), respectively; and

(B) by inserting after subparagraph (G) the following new subparagraph:

"(H) Section 1902(a)(88) (relating to address information for enrollees and prevention of simultaneous enrollments).".

(2) MANAGED CARE.—Section 2103(f)(3) of the Social Security Act (42 U.S.C. 1397cc(f)(3)) is amended by striking "and (e)" and inserting "(e), and (j)".

SEC. 71104. ENSURING DECEASED INDIVIDUALS DO NOT REMAIN ENROLLED.

Section 1902 of the Social Security Act (42 U.S.C. 1396a), as amended by section 71103, is further amended—

(1) in subsection (a)—

(A) in paragraph (87), by striking "; and" and inserting a semicolon;

(B) in paragraph (88), by striking the period at the end and inserting "; and"; and

(C) by inserting after paragraph (88) the following new paragraph:

"(89) provide that the State shall comply with the eligibility verification requirements under subsection (ww), except that this paragraph shall apply only in the case of the 50 States and the District of Columbia."; and

(2) by adding at the end the following new subsection:

"(ww) VERIFICATION OF CERTAIN ELIGIBILITY CRITERIA.—

"(1) IN GENERAL.—For purposes of subsection (a)(89), the eligibility verification requirements, beginning January 1, 2027, are as follows:

"(A) QUARTERLY SCREENING TO VERIFY ENROLLEE STATUS.—The State shall, not less frequently than quarterly, review the Death Master File (as such term is defined in section 203(d) of the Bipartisan Budget Act of 2013) or a successor system that provides such information needed to determine whether any individuals enrolled for medical assistance under the State plan (or waiver of such plan) are deceased.

"(B) DISENROLLMENT UNDER STATE PLAN.—If the State determines, based on information obtained from the Death Master File, that an individual enrolled for medical assistance under the State plan (or waiver of such plan) is deceased, the State shall—

"(i) treat such information as factual information confirming the death of a beneficiary;

"(ii) disenroll such individual from the State plan (or waiver of such plan) in accordance with subsection (a)(3); and

"(iii) discontinue any payments for medical assistance under this title made on behalf of such individual (other than payments for any items or services furnished to such individual prior to the death of such individual).

"(C) REINSTATEMENT OF COVERAGE IN THE EVENT OF ERROR.—If a State determines that an individual was misidentified as deceased based on information obtained from the Death Master File and was erroneously disenrolled from medical assistance under the State plan (or waiver of such plan) based on such misidentification, the State shall immediately re-enroll such individual under the State plan (or waiver of such plan), retroactive to the date of such disenrollment.

"(2) RULE OF CONSTRUCTION.—Nothing under this subsection shall be construed to preclude the ability of a State to use other electronic data sources to timely identify potentially deceased beneficiaries, so long as the State is also in compliance with the requirements of this subsection (and all other requirements under this title relating to Medicaid eligibility determination and redetermination).".

SEC. 71105. ENSURING DECEASED PROVIDERS DO NOT REMAIN ENROLLED.

Section 1902(kk)(1) of the Social Security Act (42 U.S.C. 1396a(kk)(1)) is amended—

(1) by striking "The State" and inserting:

"(A) IN GENERAL.—The State"; and

(2) by adding at the end the following new subparagraph:

"(B) PROVIDER SCREENING AGAINST DEATH MASTER FILE.—Beginning January 1, 2028, as part of the enrollment (or reenrollment or revalidation of enrollment) of a provider or supplier under this title, and not less frequently than quarterly during the period that such provider or supplier is so enrolled, the State conducts a check of the Death Master File (as such term is defined in section 203(d) of the Bipartisan Budget Act of 2013) to determine whether such provider or supplier is deceased.".

SEC. 71106. PAYMENT REDUCTION RELATED TO CERTAIN ERRONEOUS EXCESS PAYMENTS UNDER MEDICAID.

(a) IN GENERAL.—Section 1903(u)(1) of the Social Security Act (42 U.S.C. 1396b(u)(1)) is amended—

(1) in subparagraph (A)—

(A) by inserting "for audits conducted by the Secretary, or, at the option of the Secretary, audits conducted by the State" after "exceeds 0.03"; and

(B) by inserting ", to the extent practicable" before the period at the end;

(2) in subparagraph (B)—

(A) by striking "The Secretary" and inserting "(i) Subject to clause (ii), the Secretary"; and

(B) by adding at the end the following new clause:

"(ii) The amount waived under clause (i) for a fiscal year may not exceed an amount equal to the erroneous excess payments for medical assistance described in subparagraph (D)(i)(II) made for such fiscal year that exceed the allowable error rate of 0.03.".

(3) in subparagraph (C), by striking "he" in each place it appears and inserting "the Secretary" in each such place; and

(4) in subparagraph (D)(i)—

(A) in subclause (I), by striking "and" at the end;

(B) in subclause (II), by striking the period at the end and inserting ", or payments where insufficient information is available to confirm eligibility, and"; and

(C) by adding at the end the following new subclause:

"(III) payments (other than payments described in subclause (I)) for items and services furnished to an individual who is not eligible for medical assistance under the State plan (or a waiver of such plan) with respect to such items and services, or payments where insufficient information is available to confirm eligibility.".

(b) EFFECTIVE DATE.—The amendments made by subsection (a) shall apply beginning with respect to fiscal year 2030.

SEC. 71107. ELIGIBILITY REDETERMINATIONS.

(a) IN GENERAL.—Section 1902(e)(14) of the Social Security Act (42 U.S.C. 1396a(e)(14)) is amended by adding at the end the following new subparagraph:

"(L) FREQUENCY OF ELIGIBILITY REDETERMINATIONS FOR CERTAIN INDIVIDUALS.—

"(i) IN GENERAL.—Subject to clause (ii), with respect to redeterminations of eligibility for medical assistance under a State plan (or waiver of such plan) scheduled on or after the first day of the first quarter that begins after December 31, 2026, a State shall make such a redetermination once every 6 months for the following individuals:

"(I) Individuals enrolled under subsection (a)(10)(A)(i)(VIII).

"(II) Individuals described in such subsection who are otherwise enrolled under a waiver of such plan that provides coverage that is equivalent to minimum essential coverage (as described in section 5000A(f)(1)(A) of the Internal Revenue Code of 1986 and determined in accordance with standards prescribed by the Secretary in regulations) to all individuals described in subsection (a)(10)(A)(i)(VIII).

"(ii) EXEMPTION.—The requirements described in clause (i) shall not apply to any individual described in subsection (xx)(9)(A)(ii)(II).

"(iii) STATE DEFINED.—For purposes of this subparagraph, the term 'State' means 1 of the 50 States or the District of Columbia.".

(b) GUIDANCE.—Not later than 180 days after the date of enactment of this section, the Secretary of Health and Human Services, acting through the Administrator of the Centers for Medicare & Medicaid Services, shall issue guidance relating to the implementation of the amendments made by this section.

(c) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $75,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71108. REVISING HOME EQUITY LIMIT FOR DETERMINING ELIGIBILITY FOR LONG-TERM CARE SERVICES UNDER THE MEDICAID PROGRAM.

(a) REVISING HOME EQUITY LIMIT.—Section 1917(f)(1) of the Social Security Act (42 U.S.C. 1396p(f)(1)) is amended—

(1) in subparagraph (B)—

(A) by striking "A State" and inserting "(i) A State";

(B) in clause (i), as inserted by subparagraph (A)—

(i) by striking "'$500,000'" and inserting "the amount specified in subparagraph (A)"; and

(ii) by inserting ", in the case of an individual's home that is located on a lot that is zoned for agricultural use," after "apply subparagraph (A)"; and

(C) by adding at the end the following new clause:

"(ii) A State may elect, without regard to the requirements of section 1902(a)(1) (relating to statewideness) and section 1902(a)(10)(B) (relating to comparability), to apply subparagraph (A), in the case of an individual's home that is not described in clause (i), by substituting for the amount specified in such subparagraph, an amount that exceeds such amount, but does not exceed $1,000,000."; and

(2) in subparagraph (C)—

(A) by inserting "(other than the amount specified in subparagraph (B)(ii) (relating to certain non-agricultural homes))" after "specified in this paragraph"; and

(B) by adding at the end the following new sentence: "In the case that application of the preceding sentence would result in a dollar amount (other than the amount specified in subparagraph (B)(i) (relating to certain agricultural homes)) exceeding $1,000,000, such amount shall be deemed to be equal to $1,000,000.”.

(b) CLARIFICATION.—Section 1902 of the Social Security Act (42 U.S.C. 1396a) is amended—

(1) in subsection (r)(2), by adding at the end the following new subparagraph:

“(C) This paragraph shall not be construed as permitting a State to determine the eligibility of an individual for medical assistance with respect to nursing facility services or other long-term care services without application of the limit under section 1917(f)(1).”; and

(2) in subsection (e)(14)(D)(iv)—

(A) by striking “Subparagraphs” and inserting

“(I) IN GENERAL.—Subparagraphs”; and

(B) by adding at the end the following new subclause:

“(II) APPLICATION OF HOME EQUITY INTEREST LIMIT.—Section 1917(f) shall apply for purposes of determining the eligibility of an individual for medical assistance with respect to nursing facility services or other long-term care services.”.

(c) EFFECTIVE DATE.—The amendments made by subsection (a) shall apply beginning on January 1, 2028.

SEC. 71109. ALIEN MEDICAID ELIGIBILITY.

(a) MEDICAID.—Section 1903(v) of the Social Security Act (42 U.S.C. 1396b(v)) is amended—

(1) in paragraph (1), by striking “and (4)”and inserting “, (4), and (5)”; and

(2) by adding at the end the following new paragraph:

“(5) Notwithstanding the preceding paragraphs of this subsection, beginning on October 1, 2026, except as provided in paragraphs (2) and (4), in no event shall payment be made to a State under this section for medical assistance furnished to an individual unless such individual is—

“(A) a resident of 1 of the 50 States, the District of Columbia, or a territory of the United States; and

“(B) either—

“(i) a citizen or national of the United States;

“(ii) an alien lawfully admitted for permanent residence as an immigrant as defined by sections 101(a)(15) and 101(a)(20) of the Immigration and Nationality Act, excluding, among others, alien visitors, tourists, diplomats, and students who enter the United States temporarily with no intention of abandoning their residence in a foreign country;

“(iii) an alien who has been granted the status of Cuban and Haitian entrant, as defined in section 501(e) of the Refugee Education Assistance Act of 1980 (Public Law 96–422); or

“(iv) an individual who lawfully resides in the United States in accordance with a Compact of Free Association referred to in section 402(b)(2)(G) of the Personal Responsibility and Work Opportunity Reconciliation Act of 1996.”.

(b) CHIP.—Section 2107(e)(1) of the Social Security Act, as amended by section 71103(b), is further amended—

(1) by redesignating subparagraphs (R) through (V) as paragraphs (S) through (W), respectively; and

(2) by inserting after paragraph (Q) the following:

"(R) Section 1903(v)(5) (relating to payments for medical assistance furnished to aliens), except in relation to payments for services provided under section 2105(a)(1)(D)(ii).".

(c) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $15,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71110. EXPANSION FMAP FOR EMERGENCY MEDICAID.

(a) IN GENERAL.—Section 1905 of the Social Security Act (42 U.S.C. 1396d) is amended by adding at the end the following new subsection:

"(kk) FMAP FOR TREATMENT OF AN EMERGENCY MEDICAL CONDITION.—Notwithstanding subsection (y) and (z), beginning on October 1, 2026, the Federal medical assistance percentage for payments for care and services described in paragraph (2) of subsection 1903(v) furnished to an alien described in paragraph (1) of such subsection shall not exceed the Federal medical assistance percentage determined under subsection (b) for such State.".

(b) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $1,000,000 for fiscal year 2026, to remain available until expended.

Subchapter B—Preventing Wasteful Spending

SEC. 71111. MORATORIUM ON IMPLEMENTATION OF RULE RELATING TO STAFFING STANDARDS FOR LONG-TERM CARE FACILITIES UNDER THE MEDICARE AND MEDICAID PROGRAMS.

The Secretary of Health and Human Services shall not, during the period beginning on the date of the enactment of this section and ending September 30, 2034, implement, administer, or enforce the amendments made by the provisions of the final rule published by the Centers for Medicare & Medicaid Services on May 10, 2024, and titled "Medicare and Medicaid Programs; Minimum Staffing Standards for Long-Term Care Facilities and Medicaid Institutional Payment Transparency Reporting" (89 Fed. Reg. 40876) to the following sections of part 483 of title 42, Code of Federal Regulations:

(1) Section 483.5.

(2) Section 483.35.

SEC. 71112. REDUCING STATE MEDICAID COSTS.

(a) IN GENERAL.—Section 1902(a)(34) of the Social Security Act (42 U.S.C. 1396a(a)(34)) is amended to read as follows:

"(34) provide that in the case of any individual who has been determined to be eligible for medical assistance under the plan and—

"(A) is enrolled under paragraph (10)(A)(i)(VIII), such assistance will be made available to the individual for care and services included under the plan and furnished in or after the month before the month in which the individual made application (or application was made on the individual's behalf in the case of a deceased individual) for such assistance if such individual was (or upon application would have been) eligible for such assistance at the time such care and services were furnished; or

"(B) is not described in subparagraph (A), such assistance will be made available to the individual for care and services included under the plan and furnished in or after the second month before the month in which the individual made application (or application was made on the individual's behalf in the case of a deceased individual) for such assistance if such individual was (or upon application would have been) eligible for such assistance at the time such care and services were furnished;".

(b) DEFINITION OF MEDICAL ASSISTANCE.—Section 1905(a) of the Social Security Act (42 U.S.C. 1396d(a)) is amended by striking "in or after the third month before the month in which the recipient makes application for assistance" and inserting ", with respect to an individual described in section 1902(a)(34)(A), in or after the month before the month in which the recipient makes application for assistance, and with respect to an individual described in section 1902(a)(34)(B), in or after the second month before the month in which the recipient makes application for assistance".

(c) CHIP.—Section 2102(b)(1)(B) of the Social Security Act (42 U.S.C. 1397bb(b)(1)(B)) is amended—

(1) in clause (iv), by striking "and" at the end;

(2) in clause (v), by striking the period and inserting "; and"; and

(3) by adding at the end the following new clause:

"(vi) shall, in the case that the State elects to provide child health or pregnancy-related assistance to an individual for any period prior to the month in which the individual made application for such assistance (or application was made on behalf of the individual), provide that such assistance is not made available to such individual for items and services included under the State child health plan (or waiver of such plan) that are furnished before the second month preceding the month in which such individual made application (or application was made on behalf of such individual) for assistance.".

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to medical assistance, child health assistance, and pregnancy-related assistance with respect to individuals whose eligibility for such medical assistance, child health assistance, or pregnancy-related assistance is based on an application made on or after the first day of the first quarter that begins after December 31, 2026.

(e) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for

Medicare & Medicaid Services, $10,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71113. FEDERAL PAYMENTS TO PROHIBITED ENTITIES.

(a) IN GENERAL.—No Federal funds that are considered direct spending and provided to carry out a State plan under title XIX of the Social Security Act or a waiver of such a plan shall be used to make payments to a prohibited entity for items and services furnished during the 1-year period beginning on the date of the enactment of this Act, including any payments made directly to the prohibited entity or under a contract or other arrangement between a State and a covered organization.

(b) DEFINITIONS.—In this section:

(1) PROHIBITED ENTITY.—The term "prohibited entity" means an entity, including its affiliates, subsidiaries, successors, and clinics—

(A) that, as of the first day of the first quarter beginning after the date of enactment of this Act—

(i) is an organization described in section 501(c)(3) of the Internal Revenue Code of 1986 and exempt from tax under section 501(a) of such Code;

(ii) is an essential community provider described in section 156.235 of title 45, Code of Federal Regulations (as in effect on the date of enactment of this Act), that is primarily engaged in family planning services, reproductive health, and related medical care; and

(iii) provides for abortions, other than an abortion—

(I) if the pregnancy is the result of an act of rape or incest; or

(II) in the case where a woman suffers from a physical disorder, physical injury, or physical illness, including a life-endangering physical condition caused by or arising from the pregnancy itself, that would, as certified by a physician, place the woman in danger of death unless an abortion is performed; and

(B) for which the total amount of Federal and State expenditures under the Medicaid program under title XIX of the Social Security Act for medical assistance furnished in fiscal year 2023 made directly, or by a covered organization, to the entity or to any affiliates, subsidiaries, successors, or clinics of the entity, or made to the entity or to any affiliates, subsidiaries, successors, or clinics of the entity as part of a nationwide health care provider network, exceeded $800,000.

(2) DIRECT SPENDING.—The term "direct spending" has the meaning given that term under section 250(c) of the Balanced Budget and Emergency Deficit Control Act of 1985 (2 U.S.C. 900(c)).

(3) COVERED ORGANIZATION.—The term "covered organization" means a managed care entity (as defined in section 1932(a)(1)(B) of the Social Security Act (42 U.S.C. 1396u–2(a)(1)(B))) or a prepaid inpatient health plan or prepaid ambulatory health plan (as such terms are defined in section 1903(m)(9)(D) of such Act (42 U.S.C. 1396b(m)(9)(D))).

(4) STATE.—The term "State" has the meaning given such term in section 1101 of the Social Security Act (42 U.S.C. 1301).

(c) IMPLEMENTATION FUNDING.—For the purposes of carrying out this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $1,000,000 for fiscal year 2026, to remain available until expended.

Subchapter C—Stopping Abusive Financing Practices

SEC. 71114. SUNSETTING INCREASED FMAP INCENTIVE.

Section 1905(ii)(3) of the Social Security Act (42 U.S.C. 1396d(ii)(3)) is amended—

(1) by striking "which has not" and inserting the following: "which—

"(A) has not";

(2) in subparagraph (A), as so inserted, by striking the period at the end and inserting "; and"; and

(3) by adding at the end the following new subparagraph:

"(B) begins to expend amounts for all such individuals prior to January 1, 2026.".

SEC. 71115. PROVIDER TAXES.

(a) CHANGE IN THRESHOLD FOR HOLD HARMLESS PROVISION OF BROAD-BASED HEALTH CARE RELATED TAXES.—Section 1903(w)(4) of the Social Security Act (42 U.S.C. 1396b(w)(4)) is amended—

(1) in subparagraph (C)(ii), by inserting ", and for fiscal years beginning on or after October 1, 2026, the applicable percent determined under subparagraph (D) shall be substituted for '6 percent' each place it appears" after "each place it appears"; and

(2) by inserting after subparagraph (C)(ii), the following new subparagraph:

"(D)(i) For purposes of subparagraph (C)(ii), the applicable percent determined under this subparagraph is—

"(I) in the case of a non-expansion State or unit of local government in such State and a class of health care items or services described in section 433.56(a) of title 42, Code of Federal Regulations (as in effect on May 1, 2025)—

"(aa) if, on the date of enactment of this subparagraph, the non-expansion State or unit of local government in such State has enacted a tax and imposes such tax on such class and the Secretary determines that the tax is within the hold harmless threshold as of that date, the applicable percent of net patient revenue attributable to such class that has been so determined; and

"(bb) if, on the date of enactment of this subparagraph, the non-expansion State or unit of local government in such State has not enacted or does not impose a tax with respect to such class, 0 percent; and

"(II) in the case of an expansion State or unit of local government in such State and a class of health care items or services described in section 433.56(a) of title 42, Code of Federal Regulations (as in effect on May 1, 2025), subject to clause (iv)—

"(aa) if, on the date of enactment of this subparagraph, the expansion State or unit of local government in such State has enacted a tax and imposes such tax on such class and the Secretary determines that the tax is within the hold harmless threshold as of that date, the lower of—

"(AA) the applicable percent of net patient revenue attributable to such class that has been so determined; and

"(BB) the applicable percent specified in clause (ii) for the fiscal year; and

"(bb) if, on the date of enactment of this subparagraph, the expansion State or unit of local government in such State has not enacted or does not impose a tax with respect to such class, 0 percent.

"(ii) For purposes of clause (i)(II)(aa)(BB), the applicable percent is—

"(I) for fiscal year 2028, 5.5 percent;

"(II) for fiscal year 2029, 5 percent;

"(III) for fiscal year 2030, 4.5 percent;

"(IV) for fiscal year 2031, 4 percent; and

"(V) for fiscal year 2032 and each subsequent fiscal year, 3.5 percent.

"(iii) For purposes of clause (i):

"(I) EXPANSION STATE.—The term 'expansion State' means a State that, beginning on January 1, 2014, or on any date thereafter, elects to provide medical assistance to all individuals described in section 1902(a)(10)(A)(i)(VIII) under the State plan under this title or under a waiver of such plan.

"(II) NON-EXPANSION STATE.—The term 'non-expansion State' means a State that is not an expansion State.

"(iv) In the case of a tax of an expansion State or unit of local government in such State in effect on the date of enactment of this clause, that applies to a class of health care items or services that is described in paragraph (3) or (4) of section 433.56(a) of title 42, Code of Federal Regulations (as in effect on May 1, 2025), and for which, on such date of enactment, is within the hold harmless threshold (as determined by the Secretary), the applicable percent of net patient revenue attributable to such class that has been so determined shall apply for a fiscal year instead of the applicable percent specified in clause (ii) for the fiscal year.".

(b) NON-APPLICATION TO TERRITORIES.—The amendments made by this section shall only apply with respect to a State that is 1 of the 50 States or the District of Columbia.

(c) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $20,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71116. STATE DIRECTED PAYMENTS.

(a) IN GENERAL.—Subject to subsection (b), the Secretary of Health and Human Services (in this section referred to as the Secretary) shall revise section 438.6(c)(2)(iii) of title 42, Code of Federal Regulations (or a successor regulation) such that, with respect to a payment described in such section made for a service furnished during a rating period beginning on or after the date of the enactment of this Act, the total payment rate for such service is limited to—

(1) in the case of a State that provides coverage to all individuals described in section 1902(a)(10)(A)(i)(VIII) of the Social Security Act (42 U.S.C. 1396a(a)(10)(A)(i)(VIII)) that is equivalent to minimum essential coverage (as described in section 5000A(f)(1)(A) of the Internal Revenue Code of 1986 and determined in accordance with standards prescribed by the Secretary in regulations) under the State plan (or waiver of such plan) of such State under title XIX of such Act, 100 percent of the specified total published Medicare payment rate (or, in the absence of a specified total published Medicare payment rate, the payment rate under a Medicaid State plan (or under a waiver of such plan)); or

(2) in the case of a State other than a State described in paragraph (1), 110 percent of the specified total published Medicare payment rate (or, in the absence of a specified total published Medicare payment rate, the payment rate under a Medicaid State plan (or under a waiver of such plan)).

(b) GRANDFATHERING CERTAIN PAYMENTS.—In the case of a payment described in section 438.6(c)(2)(iii) of title 42, Code of Federal Regulations (or a successor regulation) for which written prior approval (or a good faith effort to receive such approval, as determined by the Secretary) was made before May 1, 2025, or a payment described in such section for a rural hospital (as defined in subsection (d)(2)) for which written prior approval (or a good faith effort to receive such approval, as determined by the Secretary) was made by the date of enactment of this Act, for the rating period occurring within 180 days of the date of the enactment of this Act, or a payment so described for such rating period for which a completed preprint was submitted to the Secretary prior to the date of enactment of this Act, beginning with the rating period on or after January 1, 2028, the total amount of such payment shall be reduced by 10 percentage points each year until the total payment rate for such service is equal to the rate for such service specified in subsection (a).

(c) TREATMENT OF EXPANSION STATES.—The revisions described in subsection (a) shall provide that, with respect to a State that begins providing the coverage described in paragraph (1) of such subsection on or after the date of the enactment of this Act, the limitation described in such paragraph shall apply to such State with respect to a payment described in section 438.6(c)(2)(iii) of title 42, Code of Federal Regulations (or a successor regulation) for a service furnished during a rating period beginning on or after the date of enactment of this Act.

(d) DEFINITIONS.—In this section:

(1) RATING PERIOD.—The term "rating period" has the meaning given such term in section 438.2 of title 42, Code of Federal Regulations (or a successor regulation).

(2) RURAL HOSPITAL.—The term "rural hospital" means the following:

(A) A subsection (d) hospital (as defined in paragraph (1)(B) of section 1886(d) of the Social Security Act (42 U.S.C. 1395ww(d))) that—

(i) is located in a rural area (as defined in paragraph (2)(D) of such section);

(ii) is treated as being located in a rural area pursuant to paragraph (8)(E) of such section; or

(iii) is located in a rural census tract of a metropolitan statistical area (as determined under the most recent modification of the Goldsmith Modification, originally published in the Federal Register on February 27, 1992 (57 Fed. Reg. 6725)).

(B) A critical access hospital (as defined in section 1861(mm)(1) of such Act (42 U.S.C. 1395x(mm)(1))).

(C) A sole community hospital (as defined in section 1886(d)(5)(D)(iii) of such Act (42 U.S.C. 1395ww(d)(5)(D)(iii))).

(D) A Medicare-dependent, small rural hospital (as defined in section 1886(d)(5)(G)(iv) of such Act (42 U.S.C. 1395ww(d)(5)(G)(iv))).

(E) A low-volume hospital (as defined in section 1886(d)(12)(C) of such Act (42 U.S.C. 1395ww(d)(12)(C))).

(F) A rural emergency hospital (as defined in section 1861(kkk)(2) of such Act (42 U.S.C. 1395x(kkk)(2))).

(3) STATE.—The term "State" means 1 of the 50 States or the District of Columbia.

(4) TOTAL PUBLISHED MEDICARE PAYMENT RATE.—The term "total published Medicare payment rate" has the meaning given to such term in section 438.6(a) of title 42, Code of Federal Regulations (or a successor regulation).

(5) WRITTEN PRIOR APPROVAL.—The term "written prior approval" has the meaning given to such term in section 438.6(c)(2)(i) of title 42, Code of Federal Regulations (or a successor regulation).

(e) FUNDING.—There are appropriated out of any monies in the Treasury not otherwise appropriated $7,000,000 for each of fiscal years 2026 through 2033 for purposes of carrying out this section, to remain available until expended.

SEC. 71117. REQUIREMENTS REGARDING WAIVER OF UNIFORM TAX REQUIREMENT FOR MEDICAID PROVIDER TAX.

(a) IN GENERAL.—Section 1903(w) of the Social Security Act (42 U.S.C. 1396b(w)) is amended—

(1) in paragraph (3)(E), by inserting after clause (ii)(II) the following new clause:

"(iii) For purposes of clause (ii)(I), a tax is not considered to be generally redistributive if any of the following conditions apply:

"(I) Within a permissible class, the tax rate imposed on any taxpayer or tax rate group (as defined in paragraph (7)(J)) explicitly defined by its relatively lower volume or percentage of Medicaid taxable units (as defined in paragraph (7)(H)) is lower than the tax rate imposed on any other taxpayer or tax rate group explicitly defined by its relatively higher volume or percentage of Medicaid taxable units.

"(II) Within a permissible class, the tax rate imposed on any taxpayer or tax rate group (as so defined) based upon its Medicaid taxable units (as so defined) is higher than the tax rate imposed on any taxpayer or tax rate group based upon its non-Medicaid taxable unit (as defined in paragraph (7)(I)).

"(III) The tax excludes or imposes a lower tax rate on a taxpayer or tax rate group (as so defined) based on or defined by any description that results in the same effect as described in subclause (I) or (II) for a taxpayer or tax rate group. Characteristics that may indicate such type of exclusion include the use of terminology to establish a tax rate group—

"(aa) based on payments or expenditures made under the program under this title without mentioning the term 'Medicaid' (or any similar term) to accomplish the same effect as described in subclause (I) or (II); or

"(bb) that closely approximates a taxpayer or tax rate group under the program under this title, to the same effect as described in subclause (I) or (II)."; and

(2) in paragraph (7), by adding at the end the following new subparagraphs:

"(H) The term 'Medicaid taxable unit' means a unit that is being taxed within a health care related tax that is applicable to the program under this title. Such term includes a unit that is used as the basis for—

"(i) payment under the program under this title (such as Medicaid bed days);

"(ii) Medicaid revenue;

"(iii) costs associated with the program under this title (such as Medicaid charges, claims, or expenditures); and

"(iv) other units associated with the program under this title, as determined by the Secretary.

"(I) The term 'non-Medicaid taxable unit' means a unit that is being taxed within a health care related tax that is not applicable to the program under this title. Such term includes a unit that is used as the basis for—

"(i) payment by non-Medicaid payers (such as non-Medicaid bed days);

"(ii) non-Medicaid revenue;

"(iii) costs that are not associated with the program under this title (such as non-Medicaid charges, non-Medicaid claims, or non-Medicaid expenditures); and

"(iv) other units not associated with the program under this title, as determined by the Secretary.

"(J) The term 'tax rate group' means a group of entities contained within a permissible class of a health care related tax that are taxed at the same rate.".

(b) NON-APPLICATION TO TERRITORIES.—The amendments made by this section shall only apply with respect to a State that is 1 of the 50 States or the District of Columbia.

(c) EFFECTIVE DATE.—The amendments made by this section shall take effect upon the date of enactment of this Act, subject to any applicable transition period determined appropriate by the Secretary of Health and Human Services, not to exceed 3 fiscal years.

SEC. 71118. REQUIRING BUDGET NEUTRALITY FOR MEDICAID DEMONSTRATION PROJECTS UNDER SECTION 1115.

(a) IN GENERAL.—Section 1115 of the Social Security Act (42 U.S.C. 1315) is amended by adding at the end the following new subsection:

"(g) REQUIREMENT OF BUDGET NEUTRALITY FOR MEDICAID DEMONSTRATION PROJECTS.—

"(1) IN GENERAL.—Beginning January 1 2027, the Secretary may not approve an application for (or renewal or amendment of) an experimental, pilot, or demonstration project undertaken under subsection (a) to promote the objectives of title XIX in a State (in this subsection referred to as a 'Medicaid demonstration project') unless the Chief Actuary for the Centers for Medicare & Medicaid Services certifies that such project, or, in the case of a renewal, the duration of the preceding waiver, is not expected to result in an increase in the amount of Federal expenditures compared to the amount that such expenditures would otherwise be in the absence of such project. For purposes of this subsection, expenditures for the coverage of populations and services that the State could have otherwise provided through its Medicaid State plan or other authority under title XIX, including expenditures that could be made under such authority but for the provision of such services at a different site of service than authorized under such State plan or other authority, shall be considered expenditures in the absence of such a project.

"(2) TREATMENT OF SAVINGS.—In the event that expenditures with respect to a State under a Medicaid demonstration project are, during an approval period for such project, less than the amount of such expenditures that would have otherwise been made in the absence of such project, the Secretary shall specify the methodology to be used with respect to the subsequent approval period for such project for purposes of taking the difference between such expenditures into account.".

(b) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $5,000,000 for each of fiscal years 2026 and 2027, to remain available until expended.

Subchapter D—Increasing Personal Accountability

SEC. 71119. REQUIREMENT FOR STATES TO ESTABLISH MEDICAID COMMUNITY ENGAGEMENT REQUIREMENTS FOR CERTAIN INDIVIDUALS.

(a) IN GENERAL.—Section 1902 of the Social Security Act (42 U.S.C. 1396a), as amended by sections 71103 and 71104, is further amended by adding at the end the following new subsection:

"(xx) COMMUNITY ENGAGEMENT REQUIREMENT FOR APPLICABLE INDIVIDUALS.—

"(1) IN GENERAL.—Except as provided in paragraph (11), beginning not later than the first day of the first quarter that begins after December 31, 2026, or, at the option of the State under a waiver or demonstration project under section 1115 or the State plan, such earlier date as the State may specify, subject to the succeeding provisions of this subsection, a State shall provide, as a condition of eligibility for medical assistance for an applicable individual, that such individual is required to demonstrate community engagement under paragraph (2)—

"(A) in the case of an applicable individual who has filed an application for medical assistance under a State plan (or a waiver of such plan) under this title, for 1 or more but not more than 3 (as specified by the State) consecutive months immediately preceding the month during which such individual applies for such medical assistance; and

"(B) in the case of an applicable individual enrolled and receiving medical assistance under a State plan (or under a waiver of such plan) under this title, for 1 or more (as specified by the State) months, whether or not consecutive—

"(i) during the period between such individual's most recent determination (or redetermination, as applicable) of eligibility and such individual's next regularly scheduled redetermination of eligibility (as verified by the State as part of such regularly scheduled redetermination of eligibility); or

"(ii) in the case of a State that has elected under paragraph (4) to conduct more frequent verifications of compliance with the requirement to demonstrate community engagement, during the period between the most recent and next such verification with respect to such individual.

"(2) COMMUNITY ENGAGEMENT COMPLIANCE DESCRIBED.—Subject to paragraph (3), an applicable individual demonstrates community engagement under this paragraph for a month if such individual meets 1 or more of the following conditions with respect to such month, as determined in accordance with criteria established by the Secretary through regulation:

"(A) The individual works not less than 80 hours.

"(B) The individual completes not less than 80 hours of community service.

"(C) The individual participates in a work program for not less than 80 hours.

"(D) The individual is enrolled in an educational program at least half-time.

"(E) The individual engages in any combination of the activities described in subparagraphs (A) through (D), for a total of not less than 80 hours.

"(F) The individual has a monthly income that is not less than the applicable minimum wage requirement under section 6 of the Fair Labor Standards Act of 1938, multiplied by 80 hours.

"(G) The individual had an average monthly income over the preceding 6 months that is not less than the applicable minimum wage requirement under section 6 of the Fair Labor Standards Act of 1938 multiplied by 80 hours, and is a seasonal worker, as described in section 45R(d)(5)(B) of the Internal Revenue Code of 1986 .

"(3) EXCEPTIONS.—

"(A) MANDATORY EXCEPTION FOR CERTAIN INDIVIDUALS.—The State shall deem an applicable individual to have demonstrated community engagement under paragraph (2) for a month, and may elect to not require an individual to verify information resulting in such deeming, if—

"(i) for part or all of such month, the individual—

"(I) was a specified excluded individual (as defined in paragraph (9)(A)(ii)); or

"(II) was—

"(aa) under the age of 19;

"(bb) entitled to, or enrolled for, benefits under part A of title XVIII, or enrolled for benefits under part B of title XVIII; or

"(cc) described in any of subclauses (I) through (VII) of subsection (a)(10)(A)(i); or

"(ii) at any point during the 3-month period ending on the first day of such month, the individual was an inmate of a public institution.

"(B) OPTIONAL EXCEPTION FOR SHORT-TERM HARDSHIP EVENTS.—

"(i) IN GENERAL.—The State plan (or waiver of such plan) may provide, in the case of an applicable individual who experiences a short-term hardship event during a month, that the State shall, under procedures established by the State (in accordance with standards specified by the Secretary), in the case of a short-term hardship event described in clause (ii)(II) and, upon the request of such individual, a short-term hardship event described in subclause (I) or (III) of clause (ii), deem such individual to have demonstrated community engagement under paragraph (2) for such month.

"(ii) SHORT-TERM HARDSHIP EVENT DEFINED.—For purposes of this subparagraph, an applicable individual experiences a short-term hardship event during a month if, for part or all of such month—

"(I) such individual receives inpatient hospital services, nursing facility services, services in an intermediate care facility for individuals with intellectual disabilities, inpatient psychiatric hospital services, or such other services of similar acuity (including outpatient care relating to other services specified in this subclause) as the Secretary determines appropriate;

"(II) such individual resides in a county (or equivalent unit of local government)—

"(aa) in which there exists an emergency or disaster declared by the President pursuant to the National Emergencies Act or the Robert T. Stafford Disaster Relief and Emergency Assistance Act; or

"(bb) that, subject to a request from the State to the Secretary, made in such form, at such time, and containing such information as the Secretary may require, has an unemployment rate that is at or above the lesser of—

"(AA) 8 percent; or

"(BB) 1.5 times the national unemployment rate; or

"(III) such individual or their dependent must travel outside of their community for an extended period of time to receive medical services necessary to treat a serious or complex medical condition (as described in paragraph (9)(A)(ii)(V)(ee)) that are not available within their community of residence.

"(4) OPTION TO CONDUCT MORE FREQUENT COMPLIANCE VERIFICATIONS.—With respect to an applicable individual enrolled and receiving medical assistance under a State plan (or a waiver of such plan) under this title, the State shall verify (in accordance with procedures specified by the Secretary) that each such individual has met the requirement to demonstrate community engagement under paragraph (1) during each such individual's regularly scheduled redetermination of eligibility, except that a State may provide for such verifications more frequently.

"(5) EX PARTE VERIFICATIONS.—For purposes of verifying that an applicable individual has met the requirement to demonstrate community engagement under paragraph (1), or determining such individual to be deemed to have demonstrated community engagement under paragraph (3), or that an individual is a specified excluded individual under paragraph (9)(A)(ii), the State shall, in accordance with standards established by the Secretary, establish processes and use reliable information available to the State (such as payroll data or payments or encounter data under this title for individuals and data on payments to such individuals for the provision of services covered under this title) without requiring, where possible, the applicable individual to submit additional information.

"(6) PROCEDURE IN THE CASE OF NONCOMPLIANCE.—

"(A) IN GENERAL.—If a State is unable to verify that an applicable individual has met the requirement to demonstrate community engagement under paragraph (1) (including, if applicable, by verifying that such individual was deemed to have demonstrated community engagement under paragraph (3)) the State shall (in accordance with standards specified by the Secretary)—

"(i) provide such individual with the notice of noncompliance described in subparagraph (B);

"(ii)(I) provide such individual with a period of 30 calendar days, beginning on the date on which such notice of noncompliance is received by the individual, to—

"(aa) make a satisfactory showing to the State of compliance with such requirement (including, if applicable, by showing that such individual was or should be deemed to have demonstrated community engagement under paragraph (3)); or

"(bb) make a satisfactory showing to the State that such requirement does not apply to such individual on the basis that such individual does not meet the definition of applicable individual under paragraph (9)(A); and

"(II) if such individual is enrolled under the State plan (or a waiver of such plan) under this title, continue to provide such individual with medical assistance during such 30-calendar-day period; and

"(iii) if no such satisfactory showing is made and the individual is not a specified excluded individual described in paragraph (9)(A)(ii), deny such individual's application for medical assistance under the State plan (or waiver of such plan) or, as applicable, disenroll such individual from the plan (or waiver of such plan) not later than the end of the month following the month in which such 30-calendar-day period ends, provided that—

"(I) the State first determines whether, with respect to the individual, there is any other basis for eligibility for medical assistance under the State plan (or waiver of such plan) or for another insurance affordability program; and

"(II) the individual is provided written notice and granted an opportunity for a fair hearing in accordance with subsection (a)(3).

"(B) NOTICE.—The notice of noncompliance provided to an applicable individual under subparagraph (A)(i) shall include information (in accordance with standards specified by the Secretary) on—

"(i) how such individual may make a satisfactory showing of compliance with such requirement (as described in subparagraph (A)(ii)) or make a satisfactory showing that such requirement does not apply to such individual on the basis that such individual does not meet the definition of applicable individual under paragraph (9)(A); and

"(ii) how such individual may reapply for medical assistance under the State plan (or a waiver of such plan) under this title in the case that such individuals' application is denied or, as applicable, in the case that such individual is disenrolled from the plan (or waiver).

"(7) TREATMENT OF NONCOMPLIANT INDIVIDUALS IN RELATION TO CERTAIN OTHER PROVISIONS.—

"(A) CERTAIN FMAP INCREASES.—A State shall not be treated as not providing medical assistance to all individuals described in section 1902(a)(10)(A)(i)(VIII), or as not expending amounts for all such individuals under the State plan (or waiver of such plan), solely because such an individual is determined ineligible for medical assistance under the State plan (or waiver) on the basis of a failure to meet the requirement to demonstrate community engagement under paragraph (1).

"(B) OTHER PROVISIONS.—For purposes of section 36B(c)(2)(B) of the Internal Revenue Code of 1986, an individual shall be deemed to be eligible for minimum essential coverage described in section 5000A(f)(1)(A)(ii) of such Code for a month if such individual would have been eligible for medical assistance under a State plan (or a waiver of such plan) under this title but for a failure to meet the requirement to demonstrate community engagement under paragraph (1).

"(8) OUTREACH.—

"(A) IN GENERAL.—In accordance with standards specified by the Secretary, beginning not later than the date that precedes December 31, 2026 (or, if the State elects under paragraph (1) to specify an earlier date, such earlier date) by the number of months specified by the State under paragraph (1)(A) plus 3 months, and periodically thereafter, the State shall notify applicable individuals enrolled under a State plan (or waiver) under this title of the requirement to demonstrate community engagement under this subsection. Such notice shall include information on—

"(i) how to comply with such requirement, including an explanation of the exceptions to such requirement under paragraph (3) and the definition of the term 'applicable individual' under paragraph (9)(A);

"(ii) the consequences of noncompliance with such requirement; and

"(iii) how to report to the State any change in the individual's status that could result in—

"(I) the applicability of an exception under paragraph (3) (or the end of the applicability of such an exception); or

"(II) the individual qualifying as a specified excluded individual under paragraph (9)(A)(ii).

"(B) FORM OF OUTREACH NOTICE.—A notice required under subparagraph (A) shall be delivered—

"(i) by regular mail (or, if elected by the individual, in an electronic format); and

"(ii) in 1 or more additional forms, which may include telephone, text message, an internet website, other commonly available electronic means, and such other forms as the Secretary determines appropriate.

"(9) DEFINITIONS.—In this subsection:

"(A) APPLICABLE INDIVIDUAL.—

"(i) IN GENERAL.—The term 'applicable individual' means an individual (other than a specified excluded individual (as defined in clause (ii)))—

"(I) who is eligible to enroll (or is enrolled) under the State plan under subsection (a)(10)(A)(i)(VIII); or

"(II) who—

"(aa) is otherwise eligible to enroll (or is enrolled) under a waiver of such plan that provides coverage that is equivalent to minimum essential coverage (as described in section 5000A(f)(1)(A) of the Internal Revenue Code of 1986 and as determined in accordance with standards prescribed by the Secretary in regulations); and

"(bb) has attained the age of 19 and is under 65 years of age, is not pregnant, is not entitled to, or enrolled for, benefits under part A of title XVIII, or enrolled for benefits under part B of title XVIII, and is not otherwise eligible to enroll under such plan.

"(ii) SPECIFIED EXCLUDED INDIVIDUAL.—For purposes of clause (i), the term 'specified excluded individual' means an individual, as determined by the State (in accordance with standards specified by the Secretary)—

"(I) who is described in subsection (a)(10)(A)(i)(IX);

"(II) who—

"(aa) is an Indian or an Urban Indian (as such terms are defined in paragraphs (13) and (28) of section 4 of the Indian Health Care Improvement Act);

"(bb) is a California Indian described in section 809(a) of such Act; or

"(cc) has otherwise been determined eligible as an Indian for the Indian Health Service under regulations promulgated by the Secretary;

"(III) who is the parent, guardian, caretaker relative, or family caregiver (as defined in section 2 of the RAISE Family Caregivers Act) of a dependent child 13 years of age and under or a disabled individual;

"(IV) who is a veteran with a disability rated as total under section 1155 of title 38, United States Code;

"(V) who is medically frail or otherwise has special medical needs (as defined by the Secretary), including an individual—

"(aa) who is blind or disabled (as defined in section 1614);

"(bb) with a substance use disorder;

"(cc) with a disabling mental disorder;

"(dd) with a physical, intellectual or developmental disability that significantly impairs their ability to perform 1 or more activities of daily living; or

"(ee) with a serious or complex medical condition;

"(VI) who—

"(aa) is in compliance with any requirements imposed by the State pursuant to section 407; or

"(bb) is a member of a household that receives supplemental nutrition assistance program benefits under the Food and Nutrition Act of 2008 and is not exempt from a work requirement under such Act;

"(VII) who is participating in a drug addiction or alcoholic treatment and rehabilitation program (as defined in section 3(h) of the Food and Nutrition Act of 2008);

"(VIII) who is an inmate of a public institution; or

"(IX) who is pregnant or entitled to postpartum medical assistance under paragraph (5) or (16) of subsection (e).

"(B) EDUCATIONAL PROGRAM.—The term 'educational program' includes—

"(i) an institution of higher education (as defined in section 101 of the Higher Education Act of 1965); and

"(ii) a program of career and technical education (as defined in section 3 of the Carl D. Perkins Career and Technical Education Act of 2006).

"(C) STATE.—The term 'State' means 1 of the 50 States or the District of Columbia.

"(D) WORK PROGRAM.—The term 'work program' has the meaning given such term in section 6(o)(1) of the Food and Nutrition Act of 2008.

"(10) PROHIBITING WAIVER OF COMMUNITY ENGAGEMENT REQUIREMENTS.—Notwithstanding section 1115(a), the provisions of this subsection may not be waived.

"(11) SPECIAL IMPLEMENTATION RULE.—

"(A) IN GENERAL.—Subject to subparagraph (C), the Secretary may exempt a State from compliance with the requirements of this subsection if—

"(i) the State submits to the Secretary a request for such exemption, made in such form and at such time as the Secretary may require, and including the information specified in subparagraph (B); and

"(ii) the Secretary determines that based on such request, the State is demonstrating a good faith effort to comply with the requirements of this subsection.

"(B) GOOD FAITH EFFORT DETERMINATION.—In determining whether a State is demonstrating a good faith effort for purposes of subparagraph (A)(ii), the Secretary shall consider—

"(i) any actions taken by the State toward compliance with the requirements of this subsection;

"(ii) any significant barriers to or challenges in meeting such requirements, including related to funding, design, development, procurement, or installation of necessary systems or resources;

"(iii) the State's detailed plan and timeline for achieving full compliance with such requirements, including any milestones of such plan (as defined by the Secretary); and

"(iv) any other criteria determined appropriate by the Secretary.

"(C) DURATION OF EXEMPTION.—

"(i) IN GENERAL.—An exemption granted under subparagraph (A) shall expire not later than December 31, 2028, and may not be renewed beyond such date.

"(ii) EARLY TERMINATION.—The Secretary may terminate an exemption granted under subparagraph (A) prior to the expiration date of such exemption if the Secretary determined that the State has—

"(I) failed to comply with the reporting requirements described in subparagraph (D); or

"(II) based on the information provided pursuant to subparagraph (D), failed to make continued good faith efforts toward compliance with the requirements of this subsection.

"(D) REPORTING REQUIREMENTS.—A State granted an exemption under subparagraph (A) shall submit to the Secretary—

"(i) quarterly progress reports on the State's status in achieving the milestones toward full compliance described in subparagraph (B)(iii); and

"(ii) information on specific risks or newly identified barriers or challenges to full compliance, including the State's plan to mitigate such risks, barriers, or challenges.".

(b) CONFORMING AMENDMENT.—Section 1902(a)(10)(A)(i)(VIII) of the Social Security Act (42 U.S.C. 1396a(a)(10)(A)(i)(VIII)) is amended by striking "subject to subsection (k)" and inserting "subject to subsections (k) and (xx)".

(c) PROHIBITING CONFLICTS OF INTEREST.—A State shall not use a Medicaid managed care entity or other specified entity (as such terms are defined in section 1903(m)(9)(D)), or other contractor to determine beneficiary compliance under such section unless the contractor has no direct or indirect financial relationship with any Medicaid managed care entity or other specified entity that is responsible for providing or arranging for coverage of medical assistance for individuals enrolled with the entity pursuant to a contract with such State.

(d) INTERIM FINAL RULEMAKING.—Not later than June 1, 2026, the Secretary of Health and Human Services shall promulgate an interim final rule for purposes of implementing the provisions of, and the amendments made by, this section. Any action taken to implement the provisions of, and the amendments made by, this section shall not be subject to the provisions of section 553 of title 5, United States Code.

(e) DEVELOPMENT OF GOVERNMENT EFFICIENCY GRANTS TO STATES.—

(1) IN GENERAL.—In order for States to establish systems necessary to carry out the provisions of, and amendments made by, this section or other sections of this chapter that pertain to conducting eligibility determinations or redeterminations, the Secretary of Health and Human Services shall—

(A) out of amounts appropriated under paragraph (3)(A), award to each State a grant equal to the amount specified in paragraph (2) for such State; and

(B) out of amounts appropriated under paragraph (3)(B), distribute an equal amount among such States.

(2) AMOUNT SPECIFIED.—For purposes of paragraph (1)(A), the amount specified in this paragraph is an amount that bears the same ratio to the amount appropriated under paragraph (3)(A) as the number of applicable individuals (as defined in section 1902(xx) of the Social Security Act, as added by subsection (a)) residing in such State bears to the total number of such individuals residing in all States, as of March 31, 2025.

(3) FUNDING.—There are appropriated, out of any monies in the Treasury not otherwise appropriated—

(A) $100,000,000 for fiscal year 2026 for purposes of awarding grants under paragraph (1)(A), to remain available until expended; and

(B) $100,000,000 for fiscal year 2026 for purposes of award grants under paragraph (1)(B), to remain available until expended.

(4) DEFINITION.—In this subsection, the term "State" means 1 of the 50 States and the District of Columbia.

(f) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $200,000,000 for fiscal year 2026, to remain available until expended.

SEC. 71120. MODIFYING COST SHARING REQUIREMENTS FOR CERTAIN EXPANSION INDIVIDUALS UNDER THE MEDICAID PROGRAM.

(a) IN GENERAL.—Section 1916 of the Social Security Act (42 U.S.C. 1396o) is amended—

(1) in subsection (a), in the matter preceding paragraph (1), by inserting "(other than, beginning October 1, 2028, specified individuals (as defined in subsection (k)(3)))" after "individuals"; and

(2) by adding at the end the following new subsection:

"(k) SPECIAL RULES FOR CERTAIN EXPANSION INDIVIDUALS.—

"(1) PREMIUMS.—Beginning October 1, 2028, the State plan shall provide that in the case of a specified individual (as defined in paragraph (3)) who is eligible under the plan, no enrollment fee, premium, or similar charge will be imposed under the plan.

"(2) REQUIRED IMPOSITION OF COST SHARING.—

"(A) IN GENERAL.—Subject to subparagraph (B) and subsection (j), in the case of a specified individual, the State plan shall, beginning October 1, 2028, provide for the imposition of such deductions, cost sharing, or similar charges determined appropriate by the State (in an amount greater than $0) with respect to certain care, items, or services furnished to such an individual, as determined by the State.

"(B) LIMITATIONS.—

"(i) EXCLUSION OF CERTAIN SERVICES.—In no case may a deduction, cost sharing, or similar charge be imposed under the State plan with respect to care, items, or services described in any of subparagraphs (B) through (J) of subsection (a)(2), or any primary care services, mental health care services, substance use disorder services, or services provided by a Federally qualified health center (as defined in 1905(l)(2)), certified community behavioral health clinic (as defined in section 1905(jj)(2)), or rural health clinic (as defined in 1905(l)(1)), furnished to a specified individual.

"(ii) ITEM AND SERVICE LIMITATION.—

"(I) IN GENERAL.—Except as provided in subclause (II), in no case may a deduction, cost sharing, or similar charge imposed under the State plan with respect to care or an item or service furnished to a specified individual exceed $35.

"(II) SPECIAL RULES FOR PRESCRIPTION DRUGS.—In no case may a deduction, cost sharing, or similar charge imposed under the State plan with respect to a prescription drug furnished to a specified individual exceed the limit that would be applicable under paragraph (2)(A)(i) or (2)(B) of section 1916A(c) with respect to such drug and individual if such drug so furnished were subject to cost sharing under such section.

"(iii) MAXIMUM LIMIT ON COST SHARING.—The total aggregate amount of deductions, cost sharing, or similar charges imposed under the State plan for all individuals in the family may not exceed 5 percent of the family income of the family involved, as applied on a quarterly or monthly basis (as specified by the State).

"(C) CASES OF NONPAYMENT.—Notwithstanding subsection (e), a State may permit a provider participating under the State plan to require, as a condition for the provision of care, items, or services to a specified individual entitled to medical assistance under this title for such care, items, or services, the payment of any deductions, cost sharing, or similar charges authorized to be imposed with respect to such care, items, or services. Nothing in this subparagraph shall be construed as preventing a provider from reducing or waiving the application of such deductions, cost sharing, or similar charges on a case-by-case basis.

"(3) SPECIFIED INDIVIDUAL DEFINED.—For purposes of this subsection, the term 'specified individual' means an individual who has a family income (as determined in accordance with section 1902(e)(14)) that exceeds the poverty line (as defined in section 2110(c)(5)) applicable to a family of the size involved and—

"(A) is enrolled under section 1902(a)(10)(A)(i)(VIII); or

"(B) is described in such subsection and otherwise enrolled under a waiver of the State plan that provides coverage that is equivalent to minimum essential coverage (as described in section 5000A(f)(1)(A) of the Internal Revenue Code of 1986 and determined in accordance with standards prescribed by the Secretary in regulations) to all individuals described in section 1902(a)(10)(A)(i)(VIII).

"(4) STATE DEFINED.—For purposes of this subsection, the term 'State' means 1 of the 50 States or the District of Columbia.".

(b) CONFORMING AMENDMENTS.—

(1) REQUIRED APPLICATION.—Section 1902(a)(14) of the Social Security Act (42 U.S.C. 1396a(a)(14)) is amended by inserting "and provide for imposition of such deductions, cost sharing, or similar charges for care, items, or services furnished to specified individuals (as defined in paragraph (3) of section 1916(k)) in accordance with paragraph (2) of such section" after "section 1916".

(2) NONAPPLICABILITY OF ALTERNATIVE COST SHARING.—Section 1916A(a)(1) of the Social Security Act (42 U.S.C. 1396o–1(a)(1)) is amended, in the second sentence, by striking "or (j)" and inserting "(j), or (k)".

(c) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $15,000,000 for fiscal year 2026, to remain available until expended.

Subchapter E—Expanding Access to Care

SEC. 71121. MAKING CERTAIN ADJUSTMENTS TO COVERAGE OF HOME OR COMMUNITY-BASED SERVICES UNDER MEDICAID.

(a) EXPANDING HCBS COVERAGE UNDER SECTION 1915(C) WAIVERS.—Section 1915(c) of the Social Security Act (42 U.S.C. 1396n(c)) is amended—

(1) in paragraph (3), by inserting "paragraph (11) or" before "subsection (h)(2)"; and

(2) by adding at the end the following new paragraph:

"(11) EXPANDING COVERAGE FOR HOME OR COMMUNITY-BASED SERVICES.—

"(A) IN GENERAL.—Beginning July 1, 2028, notwithstanding paragraph (1), the Secretary may approve a waiver that is standalone from any other waiver approved under this subsection to include as medical assistance under the State plan of such State payment for part or all of the cost of home or community-based services (other than room and board (as described in paragraph (1))) approved by the Secretary which are provided pursuant to a written plan of care to individuals described in subparagraph (B)(iii). A waiver approved under this paragraph shall be for an initial term of 3 years and, upon the request of the State, shall be extended for additional 5-year periods unless the Secretary determines that for the previous waiver period the requirements specified under this subsection (excluding those excepted under subparagraph (B)) have not been met.

"(B) STATE REQUIREMENTS.—In addition to the requirements specified under this subsection (except for the requirements described in subparagraphs (C) and (D) of paragraph (2) and any other requirement specified under this subsection that the Secretary determines to be inapplicable in the context of a waiver that does not require individuals to have a determination described in paragraph (1)), a State shall meet the following requirements as a condition of waiver approval:

"(i) As of the date that such State requests a waiver under this subsection to provide home or community-based services to individuals described in clause (iii), all other waivers (if any) granted under this subsection to such State meet the requirements of this subsection.

"(ii) The State demonstrates to the Secretary that approval of a waiver under this subsection with respect to individuals described in clause (iii) will not result in a material increase of the average amount of time that individuals with respect to whom a determination described in paragraph (1) has been made will need to wait to receive home or community-based services under any other waiver granted under this subsection, as determined by the Secretary.

"(iii) The State establishes needs-based criteria, subject to the approval of the Secretary, regarding who will be eligible for home or community-based services under a waiver approved under this paragraph without requiring such individuals to have a determination described in paragraph (1), and specifies the home or community-based services such individuals so eligible will receive.

"(iv) The State establishes needs-based criteria for determining whether an individual described in clause (iii) requires the level of care provided in a hospital, nursing facility, or an intermediate care facility for individuals with developmental disabilities under the State plan or under any waiver of such plan that are more stringent than the needs-based criteria established under clause (iii) for determining eligibility for home or community-based services.

"(v) The State attests that the State's average per capita expenditure for medical assistance under the State plan (or waiver of such plan) provided with respect to such individuals enrolled in a waiver under this paragraph will not exceed the State's average per capita expenditure for medical assistance for individuals receiving institutional care under the State plan (or waiver of such plan) for the duration that the waiver under this paragraph is in effect.

"(vi) The State provides to the Secretary data (in such form and manner as the Secretary may specify) regarding the number of individuals described in clause (iii) with respect to a State seeking approval of a waiver under this subsection, to whom the State will make such services available under such waiver.

"(vii) The State agrees to provide to the Secretary, not less frequently than annually, data for purposes of paragraph (2)(E) (in such form and manner as the Secretary may specify) regarding, with respect to each preceding year in which a waiver under this subsection to provide home or community-based services to individuals described in clause (iii) was in effect—

"(I) the cost (as such term is defined by the Secretary) of such services furnished to individuals described in clause (iii), broken down by type of service;

"(II) with respect to each type of home or community-based service provided under the waiver, the length of time that such individuals have received such service;

"(III) a comparison between the data described in subclause (I) and any comparable data available with respect to individuals with respect to whom a determination described in paragraph (1) has been made and with respect to individuals receiving institutional care under this title; and

"(IV) the number of individuals who have received home or community-based services under the waiver during the preceding year.

"(C) LIMITATION ON PAYMENTS.—No payments made to carry out this paragraph shall be used by a State to make payments to a third party on behalf of an individual practitioner for benefits such as health insurance, skills training, and other benefits customary for employees, in the case of a class of practitioners for which the program established under this title is the primary source of revenue.".

(b) IMPLEMENTATION FUNDING.—

(1) IN GENERAL.—There are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services—

(A) for fiscal year 2026, $50,000,000 for purposes of carrying out the provisions of, and the amendments made by, this section, to remain available until expended; and

(B) for fiscal year 2027, $100,000,000 for purposes of making payments to States, subject to paragraph (2), to support State systems to deliver home or community-based services under section 1915(c) of the Social Security Act (42 U.S.C. 1396n(c)) (as amended by this section) or under section 1115 of such Act (42 U.S.C. 1315), to remain available until expended.

(2) PAYMENTS BASED ON STATE HCBS ELIGIBLE POPULATION.—Payments to States from amounts made available by paragraph (1)(B) shall be made, with respect to a State, on the basis of the proportion of the population of the State that is receiving home or community-based services under section1915(c) of the Social Security Act (42 U.S.C. 1396n(c)) (as amended by this section) or under section 1115 of such Act (42 U.S.C. 1315), as compared to all States.

CHAPTER 2—MEDICARE

Subchapter A—Strengthening Eligibility Requirements

SEC. 71201. LIMITING MEDICARE COVERAGE OF CERTAIN INDIVIDUALS.

Title XVIII of the Social Security Act (42 U.S.C. 1395 et seq.) is amended by adding at the end the following new section:

"SEC. 1899C. LIMITING MEDICARE COVERAGE OF CERTAIN INDIVIDUALS.

"(a) IN GENERAL.—Subject to subsection (b), an individual may be entitled to, or enrolled for, benefits under this title only if the individual is—

"(1) a citizen or national of the United States;

"(2) an alien who is lawfully admitted for permanent residence under the Immigration and Nationality Act;

"(3) an alien who has been granted the status of Cuban and Haitian entrant, as defined in section 501(e) of the Refugee Education Assistance Act of 1980 (Public Law 96–422); or

"(4) an individual who lawfully resides in the United States in accordance with a Compact of Free Association referred to in section 402(b)(2)(G) of the Personal Responsibility and Work Opportunity Reconciliation Act of 1996.

"(b) APPLICATION TO INDIVIDUALS CURRENTLY ENTITLED TO OR ENROLLED FOR BENEFITS.—

"(1) IN GENERAL.—In the case of an individual who is entitled to, or enrolled for, benefits under this title as of the date of the enactment of this section, subsection (a) shall apply beginning on the date that is 18 months after such date of enactment.

"(2) REVIEW BY COMMISSIONER OF SOCIAL SECURITY.—

"(A) IN GENERAL.—Not later than 1 year after the date of the enactment of this section, the Commissioner of Social Security shall complete a review of individuals entitled to, or enrolled for, benefits under this title as of such date of enactment for purposes of identifying individuals not described in any of paragraphs (1) through (4) of subsection (a).

"(B) NOTICE.—The Commissioner of Social Security shall notify each individual identified under the review conducted under subparagraph (A) that such individual's entitlement to, or enrollment for, benefits under this title will be terminated as of the date that is 18 months after the date of the enactment of this section. Such notification shall be made as soon as practicable after such identification and in a manner designed to ensure such individual's comprehension of such notification.".

Subchapter B—Improving Services for Seniors

SEC. 71202. TEMPORARY PAYMENT INCREASE UNDER THE MEDICARE PHYSICIAN FEE SCHEDULE TO ACCOUNT FOR EXCEPTIONAL CIRCUMSTANCES.

(a) IN GENERAL.—Section 1848(t) of the Social Security Act (42 U.S.C. 1395w–4(t)) is amended—

(1) in the subsection heading, by striking "DURING 2021 THROUGH 2024";

(2) in paragraph (1)—

(A) in the matter preceding subparagraph (A), by striking "and 2024" and inserting "2024, and 2026";

(B) in subparagraph (D), by striking "and" at the end;

(C) in subparagraph (E), by striking the period at the end and inserting "; and"; and

(D) by adding at the end the following new subparagraph:

"(F) such services furnished on or after January 1, 2026, and before January 1, 2027, by 2.5 percent."; and

(3) in paragraph (2)(C)—

(A) in the subparagraph heading, by inserting "AND 2026" after "2024"; and

(B) by striking "or 2024" each place it appears and inserting "2024, or 2026".

(b) CONFORMING AMENDMENT.—Section 1848(c)(2)(B)(iv)(V) of the Social Security Act (42 U.S.C. 1395w–4(c)(2)(B)(iv)(V)) is amended by striking "or 2024" and inserting "2024, or 2026".

SEC. 71203. EXPANDING AND CLARIFYING THE EXCLUSION FOR ORPHAN DRUGS UNDER THE DRUG PRICE NEGOTIATION PROGRAM.

(a) IN GENERAL.—Section 1192(e) of the Social Security Act (42 U.S.C. 1320f–1(e)) is amended—

(1) in paragraph (1), in the matter preceding subparagraph (A), by striking "and (3)" and inserting "through (4)";

(2) in paragraph (3)(A)—

(A) by striking "only one rare disease or condition" and inserting "one or more rare diseases or conditions"; and

(B) by striking "such disease or condition" and inserting "one or more such rare diseases or conditions (as such term is defined in section 526(a)(2) of the Federal Food, Drug, and Cosmetic Act)"; and

(3) by adding at the end the following new paragraph:

"(4) TREATMENT OF FORMER ORPHAN DRUGS.—In the case of a drug or biological product that, as of the date of the approval or licensure of such drug or biological product, is a drug or biological product described in paragraph (3)(A), paragraph (1)(A)(ii) or (1)(B)(ii) (as applicable) shall apply as if the reference to 'the date of such approval' or 'the date of such licensure', respectively, were instead a reference to 'the first day after the date of such approval for which such drug is not a drug described in paragraph (3)(A)' or 'the first day after the date of such licensure for which such biological product is not a biological product described in paragraph (3)(A)', respectively.".

(b) APPLICATION.—The amendments made by subsection (a) shall apply with respect to initial price applicability years (as defined in section 1191(b) of the Social Security Act (42 U.S.C. 1320f(b))) beginning on or after January 1, 2028.

CHAPTER 3—HEALTH TAX

Subchapter A—Improving Eligibility Criteria

SEC. 71301. PERMITTING PREMIUM TAX CREDIT ONLY FOR CERTAIN INDIVIDUALS.

(a) IN GENERAL.—Section 36B(e)(1) is amended by inserting "or, in the case of aliens who are lawfully present, are not eligible aliens" after "individuals who are not lawfully present".

(b) ELIGIBLE ALIENS.—Section 36B(e)(2) is amended—

(1) by striking "For purposes of this section, an individual" and inserting "For purposes of this section—

"(A) IN GENERAL.—An individual", and

(2) by adding at the end the following new subparagraph:

"(B) ELIGIBLE ALIENS.—An individual who is an alien and lawfully present shall be treated as an eligible alien if such individual is, and is reasonably expected to be for the entire period of enrollment for which the credit under this section is being claimed—

"(i) an alien who is lawfully admitted for permanent residence under the Immigration and Nationality Act (8 U.S.C. 1101 et seq.),

"(ii) an alien who has been granted the status of Cuban and Haitian entrant, as defined in section 501(e) of the Refugee Education Assistance Act of 1980 (Public Law 96–422); or

"(iii) an individual who lawfully resides in the United States in accordance with a Compact of Free Association referred to in section 402(b)(2)(G) of the

Personal Responsibility and Work Opportunity Reconciliation Act of 1996 (8 U.S.C. 1612(b)(2)(G)).".

(c) CONFORMING AMENDMENTS.—

(1) VERIFICATION OF INFORMATION.—Section 1411 of the Patient Protection and Affordable Care Act (42 U.S.C. 18081) is amended—

(A) in subsection (a)—

(i) in paragraph (1), by striking "and section 36B(e) of the Internal Revenue Code of 1986"; and

(ii) in paragraph (2)—

(I) in subparagraph (A), by striking "and" at the end;

(II) in subparagraph (B), by adding "and" at the end; and

(III) by adding at the end the following new subparagraph:

"(C) in the case such individual is an alien lawfully present in the United States, whether such individual is an eligible alien (within the meaning of section 36B(e)(2) of such Code);";

(B) in subsection (b)(3), by adding at the end the following new subparagraph:

"(D) IMMIGRATION STATUS.—In the case the individual's eligibility is based on an attestation of the enrollee's immigration status, an attestation that such individual is an eligible alien (within the meaning of 36B(e)(2) of the Internal Revenue Code of 1986)."; and

(C) in subsection (c)(2)(B)(ii), by adding at the end the following new subclause:

"(III) In the case of an individual described in clause (i)(I) with respect to whom a premium tax credit under section 36B of the Internal Revenue Code of 1986 is being claimed, the attestation that the individual is an eligible alien (within the meaning of section 36B(e)(2) of such Code).".

(2) ADVANCE DETERMINATIONS.—Section 1412(d) of the Patient Protection and Affordable Care Act (42 U.S.C. 18082(d)) is amended by inserting before the period at the end the following: ", or credits under section 36B of the Internal Revenue Code of 1986 for aliens who are not eligible aliens (within the meaning of section 36B(e)(2) of such Code)".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall apply with respect to plan years beginning on or after January 1, 2027.

(d) REQUIREMENT TO MAINTAIN MINIMUM ESSENTIAL COVERAGE.—Section 5000A(d)(3) is amended by striking "an alien lawfully present in the United States" and inserting "an eligible alien (within the meaning of section 36B(e)(2))".

(e) EFFECTIVE DATE.—The amendments made by this section (other than the amendments made by subsection (c)) shall apply to taxable years beginning after December 31, 2026.

SEC. 71302. DISALLOWING PREMIUM TAX CREDIT DURING PERIODS OF MEDICAID INELIGIBILITY DUE TO ALIEN STATUS.

(a) IN GENERAL.—Section 36B(c)(1) is amended by striking subparagraph (B).

(b) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

Subchapter B—Preventing Waste, Fraud, and Abuse

SEC. 71303. REQUIRING VERIFICATION OF ELIGIBILITY FOR PREMIUM TAX CREDIT.

(a) IN GENERAL.—Section 36B(c) is amended by adding at the end the following new paragraphs:

"(5) EXCHANGE ENROLLMENT VERIFICATION REQUIREMENT.—

"(A) IN GENERAL.—The term 'coverage month' shall not include, with respect to any individual covered by a qualified health plan enrolled in through an Exchange, any month beginning before the Exchange verifies, using applicable enrollment information that shall be provided or verified by the applicant, such individual's eligibility—

"(i) to enroll in the plan through the Exchange, and

"(ii) for any advance payment under section 1412 of the Patient Protection and Affordable Care Act of the credit allowed under this section.

"(B) APPLICABLE ENROLLMENT INFORMATION.—For purposes of subparagraph (A), applicable enrollment information shall include affirmation of at least the following information (to the extent relevant in determining eligibility described in subparagraph (A)):

"(i) Household income and family size.

"(ii) Whether the individual is an eligible alien.

"(iii) Any health coverage status or eligibility for coverage.

"(iv) Place of residence.

"(v) Such other information as may be determined by the Secretary (in consultation with the Secretary of Health and Human Services) as necessary to the verification prescribed under subparagraph (A).

"(C) VERIFICATION OF PAST MONTHS.—In the case of a month that begins before verification prescribed by subparagraph (A), such month shall be treated as a coverage month if the Exchange verifies for such month (using applicable enrollment information that shall be provided or verified by the applicant) such individual's eligibility to have so enrolled and for any such advance payment.

"(D) EXCHANGE PARTICIPATION; COORDINATION WITH OTHER PROCEDURES FOR DETERMINING ELIGIBILITY.—An individual shall not, solely by reason of failing to meet the requirements of this paragraph with respect to a month, be treated for such month as ineligible to enroll in a qualified health plan through an Exchange.

"(E) WAIVER FOR CERTAIN SPECIAL ENROLLMENT PERIODS.—The Secretary may waive the application of subparagraph (A) in the case of an individual who enrolls in a qualified health plan through an Exchange for 1 or more months of the taxable year during a special enrollment period provided by the Exchange on the basis of a change in the family size of the individual.

"(F) INFORMATION AND RELIANCE ON THIRD-PARTY SOURCES.—An Exchange shall be permitted to use any data available to the Exchange and any reliable third-party sources in collecting information for verification by the applicant.

"(6) EXCHANGE COMPLIANCE WITH FILING REQUIREMENTS.—The term 'coverage month' shall not include, with respect to any individual covered by a qualified health plan enrolled in through an Exchange, any month for which the Exchange does not meet the requirements of section 155.305(f)(4)(iii) of title 45, Code of Federal Regulations (as published in the Federal Register on June 25, 2025 (90 Fed. Reg. 27074), applied as though it applied to all plan years after 2025), with respect to the individual.".

(b) PRE-ENROLLMENT VERIFICATION PROCESS REQUIRED.—Section 36B(c)(3)(A) is amended—

(1) by striking "HEALTH PLAN.—The term" and inserting "HEALTH PLAN.— "

"(i) IN GENERAL.—The term", and

(2) by adding at the end the following new clause:

"(ii) PRE-ENROLLMENT VERIFICATION PROCESS REQUIRED.—Such term shall not include any plan enrolled in through an Exchange, unless such Exchange provides a process for pre-enrollment verification through which any applicant may, beginning not later than August 1, verify with the Exchange the applicant's household income and eligibility for enrollment in such plan for plan years beginning in the subsequent year.".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2027.

SEC. 71304. DISALLOWING PREMIUM TAX CREDIT IN CASE OF CERTAIN COVERAGE ENROLLED IN DURING SPECIAL ENROLLMENT PERIOD.

(a) IN GENERAL.—Section 36B(c)(3)(A), as amended by the preceding provisions of this Act, is amended by adding at the end the following new clause:

"(iii) EXCEPTION IN CASE OF CERTAIN SPECIAL ENROLLMENT PERIODS.—Such term shall not include any plan enrolled in during a special enrollment period provided for by an Exchange—

"(I) on the basis of the relationship of the individual's expected household income to such a percentage of the poverty line (or such other amount) as is prescribed by the Secretary of Health and Human Services for purposes of such period, and

"(II) not in connection with the occurrence of an event or change in circumstances specified by the Secretary of Health and Human Services for such purposes.".

(b) EFFECTIVE DATE.—The amendments made by this section shall apply with respect to plan years beginning after December 31, 2025.

SEC. 71305. ELIMINATING LIMITATION ON RECAPTURE OF ADVANCE PAYMENT OF PREMIUM TAX CREDIT.

(a) IN GENERAL.—Section 36B(f)(2) is amended by striking subparagraph (B).

(b) CONFORMING AMENDMENTS.—

(1) Section 36B(f)(2) is amended by striking "ADVANCE PAYMENTS.—" and all that follows through "If the advance payments" and inserting the following: "ADVANCE PAYMENTS.—If the advance payments".

(2) Section 35(g)(12)(B)(ii) is amended by striking "then section 36B(f)(2)(B) shall be applied by substituting the amount determined under clause (i) for the amount determined under section 36B(f)(2)(A)" and inserting "then the amount determined under clause (i) shall be substituted for the amount determined under section 36B(f)(2)".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to taxable years beginning after December 31, 2025.

Subchapter C—Enhancing Choice for Patients

SEC. 71306. PERMANENT EXTENSION OF SAFE HARBOR FOR ABSENCE OF DEDUCTIBLE FOR TELEHEALTH SERVICES.

(a) IN GENERAL.—Subparagraph (E) of section 223(c)(2) is amended to read as follows:

"(E) SAFE HARBOR FOR ABSENCE OF DEDUCTIBLE FOR TELEHEALTH.—A plan shall not fail to be treated as a high deductible health plan by reason of failing to have a deductible for telehealth and other remote care services.".

(b) CERTAIN COVERAGE DISREGARDED.—Clause (ii) of section 223(c)(1)(B) is amended by striking "(in the case of months or plan years to which paragraph (2)(E) applies)".

(c) EFFECTIVE DATE.—The amendments made by this section shall apply to plan years beginning after December 31, 2024.

SEC. 71307. ALLOWANCE OF BRONZE AND CATASTROPHIC PLANS IN CONNECTION WITH HEALTH SAVINGS ACCOUNTS.

(a) IN GENERAL.—Section 223(c)(2) is amended by adding at the end the following new subparagraph:

"(H) BRONZE AND CATASTROPHIC PLANS TREATED AS HIGH DEDUCTIBLE HEALTH PLANS.—The term 'high deductible health plan' shall include any plan which is—

"(i) available as individual coverage through an Exchange established under section 1311 or 1321 of the Patient Protection and Affordable Care Act, and

"(ii) described in subsection (d)(1)(A) or (e) of section 1302 of such Act.".

(b) EFFECTIVE DATE.—The amendment made by this section shall apply to months beginning after December 31, 2025.

SEC. 71308. TREATMENT OF DIRECT PRIMARY CARE SERVICE ARRANGEMENTS.

(a) IN GENERAL.—Section 223(c)(1) is amended by adding at the end the following new subparagraph:

"(E) TREATMENT OF DIRECT PRIMARY CARE SERVICE ARRANGEMENTS.—

"(i) IN GENERAL.—A direct primary care service arrangement shall not be treated as a health plan for purposes of subparagraph (A)(ii).

"(ii) DIRECT PRIMARY CARE SERVICE ARRANGEMENT.—For purposes of this subparagraph—

"(I) IN GENERAL.—The term 'direct primary care service arrangement' means, with respect to any individual, an arrangement under which such individual is provided medical care (as defined in section 213(d)) consisting solely of primary care services provided by primary care practitioners (as defined in section 1833(x)(2)(A) of the Social Security Act, determined without regard to clause (ii) thereof), if the sole compensation for such care is a fixed periodic fee.

"(II) LIMITATION.—With respect to any individual for any month, such term shall not include any arrangement if the aggregate fees for all direct primary care service arrangements (determined without regard to this subclause) with respect to such individual for such month exceed $150 (twice such dollar amount in the case of an individual with any direct primary care service arrangement (as so determined) that covers more than one individual).

"(iii) CERTAIN SERVICES SPECIFICALLY EXCLUDED FROM TREATMENT AS PRIMARY CARE SERVICES.—For purposes of this subparagraph, the term 'primary care services' shall not include—

"(I) procedures that require the use of general anesthesia,

"(II) prescription drugs (other than vaccines), and

"(III) laboratory services not typically administered in an ambulatory primary care setting.

The Secretary, after consultation with the Secretary of Health and Human Services, shall issue regulations or other guidance regarding the application of this clause.".

(b) DIRECT PRIMARY CARE SERVICE ARRANGEMENT FEES TREATED AS MEDICAL EXPENSES.—Section 223(d)(2)(C) is amended by striking "or" at the end of clause (iii), by striking the period at the end of clause (iv) and inserting ", or", and by adding at the end the following new clause:

"(v) any direct primary care service arrangement.".

(c) INFLATION ADJUSTMENT.—Section 223(g)(1) is amended—

(1) by striking "in subsections (b)(2) and (c)(2)(A)" and inserting "in subsections (b)(2), (c)(2)(A), and in the case of taxable years beginning after 2026, (c)(1)(E)(ii)(II)",

(2) in subparagraph (B), by striking "clause (ii)" in clause (i) and inserting "clauses (ii) and (iii)", by striking "and" at the end of clause (i), by striking the period at the end of clause (ii) and inserting ", and", and by inserting after clause (ii) the following new clause:

"(iii) in the case of the dollar amount in subsection (c)(1)(E)(ii)(II), 'calendar year 2025'.", and

(3) by inserting ", (c)(1)(E)(ii)(II)," after "(b)(2)" in the last sentence.

(d) EFFECTIVE DATE.—The amendments made by this section shall apply to months beginning after December 31, 2025.

CHAPTER 4—PROTECTING RURAL HOSPITALS AND PROVIDERS

SEC. 71401. RURAL HEALTH TRANSFORMATION PROGRAM.

(a) IN GENERAL.—Section 2105 of the Social Security Act (42 U.S.C. 1397ee) is amended by adding at the end the following new subsection:

"(h) RURAL HEALTH TRANSFORMATION PROGRAM.—

"(1) APPROPRIATION.—

"(A) IN GENERAL.—There are appropriated, out of any money in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services (in this subsection referred to as the 'Administrator'), to provide allotments to States for purposes of carrying out the activities described in paragraph (6)—

"(i) $10,000,000,000 for fiscal year 2026;

"(ii) $10,000,000,000 for fiscal year 2027;

"(iii) $10,000,000,000 for fiscal year 2028;

"(iv) $10,000,000,000 for fiscal year 2029; and

"(v) $10,000,000,000 for fiscal year 2030.

"(B) UNEXPENDED OR UNOBLIGATED FUNDS.—

"(i) IN GENERAL.—Any amounts appropriated under subparagraph (A) that are unexpended or unobligated as of October 1, 2032, shall be returned to the Treasury of the United States.

"(ii) REDISTRIBUTION OF UNEXPENDED OR UNOBLIGATED FUNDS.—In carrying out subparagraph (A), the Administrator shall, not later than March 31, 2028, and annually thereafter through March 31, 2032, determine the amount of funds, if any, that are available under such subparagraph for a previous fiscal year, are unexpended or unobligated with respect to such fiscal year, and will not be available to a State in the current fiscal year, pursuant to clause (iii).

"(iii) AVAILABILITY OF FUNDS.—

"(I) IN GENERAL.—Amounts allotted to a State under this subsection for a year shall be available for expenditure by the State through the end of the fiscal year following the fiscal year in which such amounts are allotted.

"(II) AVAILABILITY OF AMOUNTS REDISTRIBUTED.—Amounts redistributed to a State under clause (ii) with respect to a fiscal year shall be available for expenditure by the State through the end of the fiscal year following the fiscal year in which such amounts are redistributed (except in the case of amounts redistributed in fiscal year 2032 which shall only be available for expenditure through September 30, 2032).

"(iv) MISUSE OF FUNDS.—If the Administrator determines that a State is not using amounts allotted or redistributed to the State under this subsection in a manner consistent with the description provided by the State in its application approved under paragraph (2), the Administrator may withhold payments to, or reduce payments to, or recover previous payments from, the State under this subsection as the

Administrator deems appropriate, and any amounts so withheld, or that remain after any such reduction, or so recovered, shall be returned to the Treasury of the United States.

"(2) APPLICATION.—

"(A) IN GENERAL.—To be eligible for an allotment under this subsection, a State shall submit to the Administrator during an application submission period to be specified by the Administrator (but that ends not later than December 31, 2025) an application in such form and manner as the Administrator may specify, that includes—

"(i) a detailed rural health transformation plan—

"(I) to improve access to hospitals, other health care providers, and health care items and services furnished to rural residents of the State;

"(II) to improve health care outcomes of rural residents of the State;

"(III) to prioritize the use of new and emerging technologies that emphasize prevention and chronic disease management;

"(IV) to initiate, foster, and strengthen local and regional strategic partnerships between rural hospitals and other health care providers in order to promote measurable quality improvement, increase financial stability, maximize economies of scale, and share best practices in care delivery;

"(V) to enhance economic opportunity for, and the supply of, health care clinicians through enhanced recruitment and training;

"(VI) to prioritize data and technology driven solutions that help rural hospitals and other rural health care providers furnish high-quality health care services as close to a patient's home as is possible;

"(VII) that outlines strategies to manage long-term financial solvency and operating models of rural hospitals in the State; and

"(VIII) that identifies specific causes driving the accelerating rate of stand-alone rural hospitals becoming at risk of closure, conversion, or service reduction;

"(ii) a certification that none of the amounts provided under this subsection shall be used by the State for an expenditure that is attributable to an intergovernmental transfer, certified public expenditure, or any other expenditure to finance the non-Federal share of expenditures required under any provision of law, including under the State plan established under this title, the State plan established under title XIX, or under a waiver of such plans; and

"(iii) such other information as the Administrator may require.

"(B) DEADLINE FOR APPROVAL.—Not later than December 31, 2025, the Administrator shall approve or deny all applications submitted for an allotment under this subsection.

"(C) ONE-TIME APPLICATION.—If an application of a State for an allotment under this subsection is approved by the Administrator, the State shall be eligible for an allotment under this subsection for each of fiscal years 2026 through 2030, except as provided in paragraph (1)(B)(iv).

"(D) ELIGIBILITY.—Only the 50 States shall be eligible for an allotment under this subsection and all references in this subsection to a State shall be treated as only referring to the 50 States.

"(3) ALLOTMENTS.—

"(A) IN GENERAL.—For each of fiscal years 2026 through 2030, the Administrator shall determine under subparagraph (B) the amount of the allotment for such fiscal year for each State with an approved application under this subsection.

"(B) AMOUNT DETERMINED.—Subject to subparagraph (C), from the amounts appropriated under paragraph (1)(A) for each of fiscal years 2026 through 2030, the Administrator shall allot—

"(i) 50 percent of the amounts appropriated for each such fiscal year equally among all States with an approved application under this subsection; and

"(ii) 50 percent of the amounts appropriated for each such fiscal year among all such States in an amount to be determined by the Administrator in accordance with subparagraph (C).

"(C) REQUIREMENTS.—In determining the amount to be allotted to a State under clause (ii) of subparagraph (B) for a fiscal year, the Administrator shall—

"(i) ensure that not less than 1⁄4 of the States with an approved application under this subsection for a fiscal year are allotted funds from amounts that are to be allotted under clause (ii) of such subparagraph; and

"(ii) consider—

"(I) the percentage of the State population that is located in a rural census tract of a metropolitan statistical area (as determined under the most recent modification of the Goldsmith Modification, originally published in the Federal Register on February 27, 1992 (57 Fed. Reg. 6725));

"(II) the proportion of rural health facilities (as defined in subparagraph (D)) in the State relative to the number of rural health facilities nationwide;

"(III) the situation of hospitals in the State, as described in section 1902(a)(13)(A)(iv); and

"(IV) any other factors that the Administrator determines appropriate.

"(D) RURAL HEALTH FACILITY DEFINED.—For the purposes of subparagraph (C)(ii), the term 'rural health facility' means the following:

"(i) A subsection (d) hospital (as defined in paragraph (1)(B) of section 1886(d)) that—

"(I) is located in a rural area (as defined in paragraph (2)(D) of such section);

"(II) is treated as being located in a rural area pursuant to paragraph (8)(E) of such section; or

"(III) is located in a rural census tract of a metropolitan statistical area (as determined under the most recent modification of the Goldsmith Modification, originally published in the Federal Register on February 27, 1992 (57 Fed. Reg. 6725)).

"(ii) A critical access hospital (as defined in section 1861(mm)(1)).

"(iii) A sole community hospital (as defined in section 1886(d)(5)(D)(iii)).

"(iv) A Medicare-dependent, small rural hospital (as defined in section 1886(d)(5)(G)(iv)).

"(v) A low-volume hospital (as defined in section 1886(d)(12)(C)).

"(vi) A rural emergency hospital (as defined in section 1861(kkk)(2)).

"(vii) A rural health clinic (as defined in section 1861(aa)(2)).

"(viii) A Federally qualified health center (as defined in section 1861(aa)(4)).

"(ix) A community mental health center (as defined in section 1861(ff)(3)(B)).

"(x) A health center that is receiving a grant under section 330 of the Public Health Service Act.

"(xi) An opioid treatment program (as defined in section 1861(jjj)(2)) that is located in a rural census tract of a metropolitan statistical area (as determined under the most recent modification of the Goldsmith Modification, originally published in the Federal Register on February 27, 1992 (57 Fed. Reg. 6725)).

"(xii) A certified community behavioral health clinic (as defined in section 1905(jj)(2)) that is located in a rural census tract of a metropolitan statistical area (as determined under the most recent modification of the Goldsmith Modification, originally published in the Federal Register on February 27, 1992 (57 Fed. Reg. 6725)).

"(4) NO MATCHING PAYMENT.—A State approved for an allotment under this subsection for a fiscal year shall not be required to provide any matching funds as a condition for receiving payments from the allotment.

"(5) TERMS AND CONDITIONS.—The Administrator shall specify such terms and conditions for allotments to States provided under this subsection as the Administrator deems appropriate, including the following:

"(A) Each State shall submit to the Administrator (at a time, and in a form and manner, specified by the Administrator)—

"(i) a plan for the State to use its allotment to carry out 3 or more of the activities described in paragraph (6); and

"(ii) annual reports on the use of allotments, including such additional information as the Administrator determines appropriate.

"(B) Not more than 10 percent of the amount allotted to a State for a fiscal year may be used by the State for administrative expenses.

"(6) USE OF FUNDS.—Amounts allotted to a State under this subsection shall be used for 3 or more of the following health-related activities:

"(A) Promoting evidence-based, measurable interventions to improve prevention and chronic disease management.

"(B) Providing payments to health care providers for the provision of health care items or services, as specified by the Administrator.

"(C) Promoting consumer-facing, technology-driven solutions for the prevention and management of chronic diseases.

"(D) Providing training and technical assistance for the development and adoption of technology-enabled solutions that improve care delivery in rural hospitals, including remote monitoring, robotics, artificial intelligence, and other advanced technologies.

"(E) Recruiting and retaining clinical workforce talent to rural areas, with commitments to serve rural communities for a minimum of 5 years.

"(F) Providing technical assistance, software, and hardware for significant information technology advances designed to improve efficiency, enhance cybersecurity capability development, and improve patient health outcomes.

"(G) Assisting rural communities to right size their health care delivery systems by identifying needed preventative, ambulatory, pre-hospital, emergency, acute inpatient care, outpatient care, and post-acute care service lines.

"(H) Supporting access to opioid use disorder treatment services (as defined in section 1861(jjj)(1)), other substance use disorder treatment services, and mental health services.

"(I) Developing projects that support innovative models of care that include value-based care arrangements and alternative payment models, as appropriate.

"(J) Additional uses designed to promote sustainable access to high quality rural health care services, as determined by the Administrator.

"(7) EXEMPTIONS.—Paragraphs (2), (3), (5), (6), (8), (10), (11), and (12) of subsection (c) do not apply to payments under this subsection.

"(8) REVIEW.—There shall be no administrative or judicial review under section 1116 or otherwise of amounts allotted or redistributed to States under this subsection, payments to States withheld or reduced under this subsection, or previous payments recovered from States under this subsection.

"(9) HEALTH CARE PROVIDER DEFINED.—For purposes of this subsection, the term 'health care provider' means a provider of services or supplier who is enrolled under this title, title XVIII, or title XIX.".

(b) CONFORMING AMENDMENTS.—Title XXI of the Social Security Act (42 U.S.C. 1397aa) is amended—

(1) in section 2101—

(A) in subsection (a), in the matter preceding paragraph (1), by striking "The purpose" and inserting "Except with respect to the rural health transformation program established in section 2105(h), the purpose"; and

(B) in subsection (b), in the matter preceding paragraph (1), by inserting "subsection (a) or (g) of" before "section 2105";

(2) in section 2105(c)(1), by striking "and may not include" and inserting "or to carry out the rural health transformation program established in subsection (h) and, except in the case of amounts made available under subsection (h), may not include"; and

(3) in section 2106(a)(1), by inserting "subsection (a) or (g) of" before "section 2105".

(c) IMPLEMENTATION.—The Administrator of the Centers for Medicare & Medicaid Services shall implement this section, including the amendments made by this section, by program instruction or other forms of program guidance.

(d) IMPLEMENTATION FUNDING.—For the purposes of carrying out the provisions of, and the amendments made by, this section, there are appropriated, out of any monies in the Treasury not otherwise appropriated, to the Administrator of the Centers for Medicare & Medicaid Services, $200,000,000 for fiscal year 2025, to remain available until expended.

Subtitle C—Increase in Debt Limit

SEC. 72001. MODIFICATION OF LIMITATION ON THE PUBLIC DEBT.

The limitation under section 3101(b) of title 31, United States Code, as most recently increased by section 401(b) of Public Law 118–5 (31 U.S.C. 3101 note), is increased by $5,000,000,000,000.

Subtitle D—Unemployment

SEC. 73001. ENDING UNEMPLOYMENT PAYMENTS TO JOBLESS MILLIONAIRES.

(a) PROHIBITION ON USE OF FEDERAL FUNDS.—

(1) IN GENERAL.—No Federal funds may be used—

(A) to make payments of unemployment compensation benefits under an unemployment compensation program of the United States in a year to an individual whose wages during the individual's base period are equal to or exceed $1,000,000; or

(B) for any administrative costs associated with making payments described in subparagraph (A).

(2) COMPLIANCE.—

(A) SELF-CERTIFICATION.—Any application for unemployment compensation under an unemployment compensation program of the United States shall include a form or procedure for an individual applicant to certify that such individual's wages during the individual's base period do not equal or exceed $1,000,000.

(B) VERIFICATION.—Each State agency that is responsible for administering any unemployment compensation program of the United States shall utilize available systems to verify wage eligibility by assessing claimant income to the degree possible.

(3) RECOVERY OF OVERPAYMENTS.—Each State agency that is responsible for administering any unemployment compensation program of the United States shall require individuals who have received amounts of unemployment compensation under such a program to which they were not entitled to repay such amounts.

(4) EFFECTIVE DATE.—The prohibition under paragraph (1) shall apply to weeks of unemployment beginning on or after the date of the enactment of this Act.

(b) UNEMPLOYMENT COMPENSATION PROGRAM OF THE UNITED STATES DEFINED.—In this section, the term "unemployment compensation program of the United States" means—

(1) unemployment compensation for Federal civilian employees under subchapter I of chapter 85 of title 5, United States Code;

(2) unemployment compensation for ex-servicemembers under subchapter II of chapter 85 of title 5, United States Code;

(3) extended benefits under the Federal-State Extended Unemployment Compensation Act of 1970 (26 U.S.C. 3304 note);

(4) any Federal temporary extension of unemployment compensation;

(5) any Federal program that increases the weekly amount of unemployment compensation payable to individuals; and

(6) any other Federal program providing for the payment of unemployment compensation, as determined by the Secretary of Labor.

TITLE VIII—COMMITTEE ON HEALTH, EDUCATION, LABOR, AND PENSIONS

Subtitle A—Exemption of Certain Assets

SEC. 80001. EXEMPTION OF CERTAIN ASSETS.

(a) EXEMPTION OF CERTAIN ASSETS.—Section 480(f)(2) of the Higher Education Act of 1965 (20 U.S.C. 1087vv(f)(2)) is amended—

(1) by striking "net value of the" and inserting the following: "net value of—

"(A) the";

(2) by striking the period at the end and inserting a semicolon; and

(3) by adding at the end the following:

"(B) a family farm on which the family resides;

"(C) a small business with not more than 100 full-time or full-time equivalent employees (or any part of such a small business) that is owned and controlled by the family; or

"(D) a commercial fishing business and related expenses, including fishing vessels and permits owned and controlled by the family.".

(b) EFFECTIVE DATE AND APPLICATION.—The amendments made by subsection (a) shall take effect on July 1, 2026, and shall apply with respect to award year 2026–2027 and each subsequent award year, as determined under the Higher Education Act of 1965 (20 U.S.C. 1001 et seq.).

Subtitle B—Loan Limits

SEC. 81001. ESTABLISHMENT OF LOAN LIMITS FOR GRADUATE AND PROFESSIONAL STUDENTS AND PARENT BORROWERS; TERMINATION OF GRADUATE AND PROFESSIONAL PLUS LOANS.

Section 455(a) of the Higher Education Act of 1965 (20 U.S.C. 1087e(a)) is amended—

(1) in paragraph (3)—

(A) in the paragraph heading, by inserting "AND FEDERAL DIRECT PLUS LOANS" after "LOANS";

(B) by striking subparagraph (A) and inserting the following:

"(A) TERMINATION OF AUTHORITY TO MAKE INTEREST SUBSIDIZED LOANS TO GRADUATE AND PROFESSIONAL STUDENTS.—Subject to subparagraph (B), and notwithstanding any provision of this part or part B—

"(i) for any period of instruction beginning on or after July 1, 2012, a graduate or professional student shall not be eligible to receive a Federal Direct Stafford loan under this part; and

"(ii) for any period of instruction beginning on July 1, 2012, and ending on June 30, 2026, the maximum annual amount of Federal Direct Unsubsidized Stafford loans such a student may borrow in any academic year (as defined in section 481(a)(2)) or its equivalent shall be the maximum annual amount for such student determined under section 428H, plus an amount equal to the amount of Federal Direct Stafford loans the student would have received in the absence of this subparagraph."; and

(C) by adding at the end the following:

"(C) TERMINATION OF AUTHORITY TO MAKE FEDERAL DIRECT PLUS LOANS TO GRADUATE AND PROFESSIONAL STUDENTS.—Subject to paragraph (8) and notwithstanding any provision of this part or part B, for any period of instruction beginning on or after July 1, 2026, a graduate or professional student shall not be eligible to receive a Federal Direct PLUS Loan under this part."; and

(2) by adding at the end the following:

"(4) GRADUATE AND PROFESSIONAL ANNUAL AND AGGREGATE LIMITS FOR FEDERAL DIRECT UNSUBSIDIZED STAFFORD LOANS BEGINNING JULY 1, 2026.—

"(A) ANNUAL LIMITS BEGINNING JULY 1, 2026.—Subject to paragraphs (7)(A) and (8), beginning on July 1, 2026, the maximum annual amount of Federal Direct Unsubsidized Stafford loans—

"(i) a graduate student, who is not a professional student, may borrow in any academic year or its equivalent shall be $20,500; and

"(ii) a professional student may borrow in any academic year or its equivalent shall be $50,000.

"(B) AGGREGATE LIMITS.—Subject to paragraphs (6), (7)(A), and (8), beginning on July 1, 2026, the maximum aggregate amount of Federal Direct Unsubsidized Stafford loans, in addition to the amount borrowed for undergraduate education, that—

"(i) a graduate student—

"(I) who is not (and has not been) a professional student, may borrow for programs of study described in subparagraph (C)(i) shall be $100,000; or

"(II) who is (or has been) a professional student, may borrow for programs of study described in subparagraph (C)(i) shall be an amount equal to—

"(aa) $200,000; minus

"(bb) the amount such student borrowed for programs of study described in subparagraph (C)(ii); and

"(ii) a professional student—

"(I) who is not (and has not been) a graduate student, may borrow for programs of study described in subparagraph (C)(ii) shall be $200,000; or

"(II) who is (or has been) a graduate student, may borrow for programs of study described in subparagraph (C)(ii) shall be an amount equal to—

"(aa) $200,000; minus

"(bb) the amount such student borrowed for programs of study described in subparagraph (C)(i).

"(C) DEFINITIONS.—

"(i) GRADUATE STUDENT.—The term 'graduate student' means a student enrolled in a program of study that awards a graduate credential (other than a professional degree) upon completion of the program.

"(ii) PROFESSIONAL STUDENT.—In this paragraph, the term 'professional student' means a student enrolled in a program of study that awards a professional degree, as defined under section 668.2 of title 34, Code of Federal Regulations (as in effect on the date of enactment of this paragraph), upon completion of the program.

"(5) PARENT BORROWER ANNUAL AND AGGREGATE LIMITS FOR FEDERAL DIRECT PLUS LOANS BEGINNING JULY 1, 2026.—

"(A) ANNUAL LIMITS.—Subject to paragraph (8) and notwithstanding any provision of this part or part B, beginning on July 1, 2026, for each dependent student, the total maximum annual amount of Federal Direct PLUS loans that may be borrowed on behalf of that dependent student by all parents of that dependent student shall be $20,000.

"(B) AGGREGATE LIMITS.—Subject to paragraph (8) and notwithstanding any provision of this part or part B, beginning on July 1, 2026, for each dependent student, the total maximum aggregate amount of Federal Direct PLUS loans that may be borrowed on behalf of that dependent student by all parents of that dependent student shall be $65,000, without regard to any amounts repaid, forgiven, canceled, or otherwise discharged on any such loan.

"(6) LIFETIME MAXIMUM AGGREGATE AMOUNT FOR ALL STUDENTS.—Subject to paragraph (8) and notwithstanding any provision of this part or part B, beginning on July 1, 2026, the maximum aggregate amount of loans made, insured, or guaranteed under this title that a student may borrow (other than a Federal Direct PLUS loan, or loan under section 428B, made to the student as a parent borrower on behalf of a dependent student) shall be $257,500, without regard to any amounts repaid, forgiven, canceled, or otherwise discharged on any such loan.

"(7) ADDITIONAL RULES REGARDING ANNUAL LOAN LIMITS.—

"(A) LESS THAN FULL-TIME ENROLLMENT.—Notwithstanding any provision of this part or part B, in any case in which a student is enrolled in a program of study of an institution of higher education on less than a full-time basis during any academic year, the amount of a loan that student may borrow for an academic year or its equivalent shall be reduced in direct proportion to the degree to which that student is not so enrolled on a full-time basis, rounded to the nearest whole percentage point, as provided in a schedule of reductions published by the Secretary computed for purposes of this subparagraph.

"(B) INSTITUTIONALLY DETERMINED LIMITS.—Notwithstanding the annual loan limits established under this section and, for undergraduate students, under this part and part B, beginning on July 1, 2026, an institution of higher education (at the discretion of a financial aid administrator at the institution) may limit the total amount of loans made under this part for a program of study for an academic year that a student may borrow, and that a parent may borrow on behalf of such student, as long as any such limit is applied consistently to all students enrolled in such program of study.

"(8) INTERIM EXCEPTION FOR CERTAIN STUDENTS.—

"(A) APPLICATION OF PRIOR LIMITS.—Paragraphs (3)(C), (4), (5), and (6) shall not apply, and paragraph (3)(A)(ii) shall apply as such paragraph was in effect for periods of instruction ending before June 30, 2026, during the expected time to credential described in subparagraph (B), with respect to an individual who, as of June 30, 2026—

"(i) is enrolled in a program of study at an institution of higher education; and

"(ii) has received a loan (or on whose behalf a loan was made) under this part for such program of study.

"(B) EXPECTED TIME TO CREDENTIAL.—For purposes of this paragraph, the expected time to credential of an individual shall be equal to the lesser of—

"(i) three academic years; or

"(ii) the period determined by calculating the difference between—

"(I) the program length for the program of study in which the individual is enrolled; and

"(II) the period of such program of study that such individual has completed as of the date of the determination under this subparagraph.

"(C) DEFINITION OF PROGRAM LENGTH.—In this paragraph, the term 'program length' means the minimum amount of time in weeks, months, or years that is specified in the catalog, marketing materials, or other official publications of an institution of higher education for a full-time student to complete the requirements for a specific program of study.".

Subtitle C—Loan Repayment

SEC. 82001. LOAN REPAYMENT.

(a) TRANSITION TO INCOME-BASED REPAYMENT PLANS.—

(1) SELECTION.—The Secretary of Education shall take such steps as may be necessary to ensure that before July 1, 2028, each borrower who has one or more loans that are in a repayment status in accordance with, or an administrative forbearance associated with, an income contingent repayment plan authorized under section 455(e) of the Higher Education Act of 1965 (referred to in this subsection as "covered income contingent loans") selects one of the following income-based repayment plans that is otherwise applicable, and for which that borrower is otherwise eligible, for the repayment of the covered income contingent loans of the borrower:

(A) The Repayment Assistance Plan under section 455(q) of the Higher Education Act of 1965.

(B) The income-based repayment plan under section 493C of the Higher Education Act of 1965.

(C) Any other repayment plan as authorized under section 455(d)(1) of the Higher Education Act of 1965.

(2) COMMENCEMENT OF NEW REPAYMENT PLAN.—Beginning on July 1, 2028, a borrower described in paragraph (1) shall begin repaying the covered income contingent loans of the borrower in accordance with the repayment plan selected under paragraph (1), unless the borrower chooses to begin repaying in accordance with the repayment plan selected under paragraph (1) before such date.

(3) FAILURE TO SELECT.—In the case of a borrower described in paragraph (1) who fails to select a repayment plan in accordance with such paragraph, the Secretary of Education shall—

(A) enroll the covered income contingent loans of such borrower in—

(i) the Repayment Assistance Plan under section 455(q) of the Higher Education Act of 1965 with respect to loans that are eligible for the Repayment Assistance Plan under such subsection; or

(ii) the income-based repayment plan under section 493C of such Act, with respect to loans that are not eligible for the Repayment Assistance Plan; and

(B) require the borrower to begin repaying covered income contingent loans according to the plans under subparagraph (A) on July 1, 2028.

(b) REPAYMENT PLANS.—Section 455(d) of the Higher Education Act of 1965 (20 U.S.C. 1087e(d)) is amended—

(1) in paragraph (1)—

(A) in the matter preceding subparagraph (A), by inserting "before July 1, 2026, who has not received a loan made under this part on or after July 1, 2026," after "made under this part";

(B) in subparagraph (D)—

(i) by inserting "before June 30, 2028," before "an income contingent repayment plan"; and

(ii) by striking "and" after the semicolon;

(C) in subparagraph (E)—

(i) by striking "that enables borrowers who have a partial financial hardship to make a lower monthly payment";

(ii) by striking "a Federal Direct Consolidation Loan, if the proceeds of such loan were used to discharge the liability on such Federal Direct PLUS Loan or a loan under section 428B made on behalf of a dependent student" and inserting "an excepted Consolidation Loan (as defined in section 493C(a)(2))"; and

(iii) by striking the period at the end and inserting "; and"; and

(D) by adding at the end the following:

"(F) beginning on July 1, 2026, the income-based Repayment Assistance Plan under subsection (q), provided that—

"(i) such Plan shall not be available for the repayment of excepted loans (as defined in paragraph (7)(E)); and

"(ii) the borrower is required to pay each outstanding loan of the borrower made under this part under such Repayment Assistance Plan, except that a borrower of an excepted loan (as defined in paragraph (7)(E)) may repay the excepted loan separately from other loans under this part obtained by the borrower.";

(2) in paragraph (5), by amending subparagraph (B) to read as follows:

"(B) repay the loan pursuant to an income-based repayment plan under subsection (q) or section 493C, as applicable."; and

(3) by adding at the end the following:

"(6) TERMINATION AND LIMITATION OF REPAYMENT AUTHORITY.—

"(A) SUNSET OF REPAYMENT PLANS AVAILABLE BEFORE JULY 1, 2026.—Paragraphs (1) through (4) of this subsection shall only apply to loans made under this part before July 1, 2026.

"(B) PROHIBITIONS.—The Secretary may not, for any loan made under this part on or after July 1, 2026—

"(i) authorize a borrower of such a loan to repay such loan pursuant to a repayment plan that is not described in paragraph (7)(A); or

"(ii) carry out or modify a repayment plan that is not described in such paragraph.

"(7) REPAYMENT PLANS FOR LOANS MADE ON OR AFTER JULY 1, 2026.—

"(A) DESIGN AND SELECTION.—Beginning on July 1, 2026, the Secretary shall offer a borrower of a loan made under this part on or after such date (including such a borrower who also has a loan made under this part before such date) two plans for repayment of the borrower's loans under this part, including principal and interest on such loans. The borrower shall be entitled to accelerate, without penalty, repayment on such loans. The borrower may choose—

"(i) a standard repayment plan—

"(I) with a fixed monthly repayment amount paid over a fixed period of time equal to the applicable period determined under subclause (II); and

"(II) with the applicable period of time for repayment determined based on the total outstanding principal of all loans of the borrower made under this part before, on, or after July 1, 2026, at the time the borrower is entering repayment under such plan, as follows—

"(aa) for a borrower with total outstanding principal of less than $25,000, a period of 10 years;

"(bb) for a borrower with total outstanding principal of not less than $25,000 and less than $50,000, a period of 15 years;

"(cc) for a borrower with total outstanding principal of not less than $50,000 and less than $100,000, a period of 20 years; and

"(dd) for a borrower with total outstanding principal of $100,000 or more, a period of 25 years; or

"(ii) the income-based Repayment Assistance Plan under subsection (q).

"(B) SELECTION BY SECRETARY.—If a borrower of a loan made under this part on or after July 1, 2026, does not select a repayment plan described in subparagraph (A), the Secretary shall provide the borrower with the standard repayment plan described in subparagraph (A)(i).

"(C) SELECTION APPLIES TO ALL OUTSTANDING LOANS.—A borrower is required to pay each outstanding loan of the borrower made under this part under the same selected repayment plan, except that a borrower who selects the Repayment Assistance Plan and also has an excepted loan that is not eligible for repayment under such Repayment Assistance Plan shall repay the excepted loan separately from other loans under this part obtained by the borrower.

"(D) CHANGES OF REPAYMENT PLAN.—A borrower may change the borrower's selection of—

"(i) the standard repayment plan under subparagraph (A)(i), or the Secretary's selection of such plan for the borrower under subparagraph (B), as the case may be, to the Repayment Assistance Plan under subparagraph (A)(ii) at any time; and

"(ii) the Repayment Assistance Plan under subparagraph (A)(ii) to the standard repayment plan under subparagraph (A)(i) at any time.

"(E) REPAYMENT FOR BORROWERS WITH EXCEPTED LOANS MADE ON OR AFTER JULY 1, 2026.—

"(i) STANDARD REPAYMENT PLAN REQUIRED.—Notwithstanding subparagraphs (A) through (D), beginning on July 1, 2026, the Secretary shall require a borrower who has received an excepted loan made on or after such date (including such a borrower who also has an excepted loan made before such date) to repay each excepted loan, including principal and interest on those excepted loans, under the standard repayment plan under subparagraph (A)(i). The borrower shall be entitled to accelerate, without penalty, repayment on such loans.

"(ii) EXCEPTED LOAN DEFINED.—For the purposes of this paragraph, the term 'excepted loan' means a loan with an outstanding balance that is—

"(I) a Federal Direct PLUS Loan that is made on behalf of a dependent student; or

"(II) a Federal Direct Consolidation Loan, if the proceeds of such loan were used to discharge the liability on—

"(aa) an excepted PLUS loan, as defined in section 493C(a)(1); or

"(bb) an excepted consolidation loan (as such term is defined in section 493C(a)(2)(A), notwithstanding subparagraph (B) of such section).".

(c) ELIMINATION OF AUTHORITY TO PROVIDE INCOME CONTINGENT REPAYMENT PLANS.—

(1) REPEAL.—Subsection (e) of section 455 of the Higher Education Act of 1965 (20 U.S.C. 1087e(e)) is repealed.

(2) FURTHER AMENDMENTS TO ELIMINATE INCOME CONTINGENT REPAYMENT.—

(A) Section 428 of the Higher Education Act of 1965 (20 U.S.C. 1078) is amended—

(i) in subsection (b)(1)(D), by striking "be subject to income contingent repayment in accordance with subsection (m)" and inserting "be subject to income-based repayment in accordance with subsection (m)"; and

(ii) in subsection (m)—

(I) in the subsection heading, by striking "INCOME CONTINGENT AND";

(II) by amending paragraph (1) to read as follows:

"(1) AUTHORITY OF SECRETARY TO REQUIRE.—The Secretary may require borrowers who have defaulted on loans made under this part that are assigned to the Secretary under subsection (c)(8) to repay those loans pursuant to an income-based repayment plan under section 493C."; and

(III) in the heading of paragraph (2), by striking "INCOME CONTINGENT OR".

(B) Section 428C of the Higher Education Act of 1965 (20 U.S.C. 1078–3) is amended—

(i) in subsection (a)(3)(B)(i)(V)(aa), by striking "for the purposes of obtaining income contingent repayment or income-based repayment" and inserting "for the purposes of qualifying for an income-based repayment plan under section 455(q) or section 493C, as applicable";

(ii) in subsection (b)(5), by striking "be repaid either pursuant to income contingent repayment under part D of this title, pursuant to income-based repayment under section 493C, or pursuant to any other repayment provision under this section" and inserting "be repaid pursuant to an income-based repayment plan under section 493C or any other repayment provision under this section"; and

(iii) in subsection (c)—

(I) in paragraph (2)(A), by striking "or by the terms of repayment pursuant to income contingent repayment offered by the Secretary under subsection (b)(5)" and inserting "or by the terms of repayment pursuant to an income-based repayment plan under section 493C"; and

(II) in paragraph (3)(B), by striking "except as required by the terms of repayment pursuant to income contingent repayment offered by the Secretary under subsection (b)(5)" and inserting "except as required by the terms of repayment pursuant to an income-based repayment plan under section 493C".

(C) Section 485(d)(1) of the Higher Education Act of 1965 (20 U.S.C. 1092(d)(1)) is amended by striking "income-contingent and".

(D) Section 494(a)(2) of the Higher Education Act of 1965 (20 U.S.C. 1098h(a)(2)) is amended—

(i) in the paragraph heading, by striking "INCOME-CONTINGENT AND INCOME-BASED" and inserting "INCOME-BASED"; and

(ii) in subparagraph (A)—

(I) in the matter preceding clause (i), by striking "income-contingent or"; and

(II) in clause (ii)(I), by striking "section 455(e)(8) or the equivalent procedures established under section 493C(c)(2)(B), as applicable" and inserting "section 493C(c)(2)".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall take effect on July 1, 2028.

(d) REPAYMENT ASSISTANCE PLAN.—Section 455 of the Higher Education Act of 1965 (20 U.S.C. 1087e) is amended by adding at the end the following new subsection:

"(q) REPAYMENT ASSISTANCE PLAN.—

"(1) IN GENERAL.—Notwithstanding any other provision of this Act, beginning on July 1, 2026, the Secretary shall carry out an income-based repayment plan (to be known as the 'Repayment Assistance Plan'), that shall have the following terms and conditions:

"(A) The total monthly repayment amount owed by a borrower for all of the loans of the borrower that are repaid pursuant to the Repayment Assistance Plan shall be equal to the applicable monthly payment of a borrower calculated under paragraph (4)(B), except that the borrower may not be precluded from repaying an amount that exceeds such amount for any month.

"(B) The Secretary shall apply the borrower's applicable monthly payment under this paragraph first toward interest due on each such loan, next toward any fees due on each loan, and then toward the principal of each loan.

"(C) Any principal due and not paid under subparagraph (B) or paragraph (2)(B) shall be deferred.

"(D) A borrower who is not in a period of deferment or forbearance shall make an applicable monthly payment for each month until the earlier of—

"(i) the date on which the outstanding balance of principal and interest due on all of the loans of the borrower that are repaid pursuant to the Repayment Assistance Plan is $0; or

"(ii) the date on which the borrower has made 360 qualifying monthly payments.

"(E) The Secretary shall cancel any outstanding balance of principal and interest due on a loan made under this part to a borrower—

"(i) who, for any period of time, participated in the Repayment Assistance Plan under this subsection;

"(ii) whose most recent payment for such loan prior to the loan cancellation under this subparagraph was made under such Repayment Assistance Plan; and

"(iii) who has made 360 qualifying monthly payments on such loan.

"(F) For the purposes of this subsection, the term 'qualifying monthly payment' means any of the following:

"(i) An on-time applicable monthly payment under this subsection.

"(ii) An on-time monthly payment under the standard repayment plan under subsection (d)(7)(A)(i) of not less than the monthly payment required under such plan.

"(iii) A monthly payment under any repayment plan (excluding the Repayment Assistance Plan under this subsection) of not less than the monthly payment that would be required under a standard repayment plan under section 455(d)(1)(A) with a repayment period of 10 years.

"(iv) A monthly payment under section 493C of not less than the monthly payment required under such section, including a monthly payment equal to the minimum payment amount permitted under such section.

"(v) A monthly payment made before July 1, 2028, under an income contingent repayment plan carried out under section 455(d)(1)(D) (or under an alternative repayment plan in lieu of repayment under such an income contingent repayment plan, if placed in such an alternative repayment plan by the Secretary) of not less than the monthly payment required under such a plan, including a monthly payment equal to the minimum payment amount permitted under such a plan.

"(vi) A month when the borrower did not make a payment because the borrower was in deferment under subsection (f)(2)(B) or due to an economic hardship described in subsection (f)(2)(D).

"(vii) A month that ended before the date of enactment of this subsection when the borrower did not make a payment because the borrower was in a period of deferment or forbearance described in section 685.209(k)(4)(iv) of title 34, Code of Federal Regulations (as in effect on the date of enactment of this subsection).

"(G) The procedures established by the Secretary under section 493C(c) shall apply for annually determining the borrower's eligibility for the Repayment Assistance Plan, including verification of a borrower's annual income and the annual amount due on the total amount of loans eligible to be repaid under this subsection, and such other procedures as are necessary to effectively implement income-based repayment under this subsection. With respect to carrying out section 494(a)(2) for the Repayment Assistance Plan, an individual may elect to opt out of the disclosures required under section 494(a)(2)(A)(ii) in accordance with the procedures established under section 493C(c)(2).

"(2) BALANCE ASSISTANCE FOR DISTRESSED BORROWERS.—

"(A) INTEREST SUBSIDY.—With respect to a borrower of a loan made under this part, for each month for which such a borrower makes an on-time applicable monthly payment required under paragraph (1)(A) and such monthly payment is insufficient to pay the total amount of interest that accrues for the month on all loans of the borrower repaid pursuant to the Repayment Assistance Plan under this subsection, the amount of interest accrued and not paid for the month shall not be charged to the borrower.

"(B) MATCHING PRINCIPAL PAYMENT.—With respect to a borrower of a loan made under this part and not in a period of deferment or forbearance, for each month for which a borrower makes an on-time applicable monthly payment required under paragraph (1)(A) and such monthly payment reduces the total outstanding principal balance of all loans of the borrower repaid pursuant to the Repayment Assistance Plan under this subsection by less than $50, the Secretary shall reduce such total outstanding principal balance of the borrower by an amount that is equal to—

"(i) the amount that is the lesser of—

"(I) $50; or

"(II) the total amount paid by the borrower for such month pursuant to paragraph (1)(A); minus

"(ii) the total amount paid by the borrower for such month pursuant to paragraph (1)(A) that is applied to such total outstanding principal balance.

"(3) ADDITIONAL DOCUMENTS.—A borrower who chooses, or is required, to repay a loan under this subsection, and for whom adjusted gross income is unavailable or does not reasonably reflect the borrower's current income, shall provide to the Secretary other documentation of income satisfactory to the Secretary, which documentation the Secretary may use to determine repayment under this subsection.

"(4) DEFINITIONS.—In this subsection:

"(A) ADJUSTED GROSS INCOME.—The term 'adjusted gross income', when used with respect to a borrower, means the adjusted gross income (as such term is defined in section 62 of the Internal Revenue Code of 1986) of the borrower (and the borrower's spouse, as applicable) for the most recent taxable year, except that, in the case of a married borrower who files a separate Federal income tax return, the term does not include the adjusted gross income of the borrower's spouse.

"(B) APPLICABLE MONTHLY PAYMENT.—

"(i) IN GENERAL.—Except as provided in clause (ii), (iii), or (vi), the term 'applicable monthly payment' means, when used with respect to a borrower, the amount equal to—

"(I) the applicable base payment of the borrower, divided by 12; minus

"(II) $50 for each dependent of the borrower (which, in the case of a married borrower filing a separate Federal income tax return, shall include only each dependent that the borrower claims on that return).

"(ii) MINIMUM AMOUNT.—In the case of a borrower with an applicable monthly payment amount calculated under clause (i) that is less than $10, the applicable monthly payment of the borrower shall be $10.

"(iii) FINAL PAYMENT.—In the case of a borrower whose total outstanding balance of principal and interest on all of the loans of the borrower that are repaid pursuant to the Repayment Assistance Plan is less than the applicable monthly payment calculated pursuant to clause (i) or (ii), as applicable, then the applicable monthly payment of the borrower shall be the total outstanding balance of principal and interest on all such loans.

"(iv) BASE PAYMENT.—The amount of the applicable base payment for a borrower with an adjusted gross income of—

"(I) not more than $10,000, is $120;

"(II) more than $10,000 and not more than $20,000, is 1 percent of such adjusted gross income;

"(III) more than $20,000 and not more than $30,000, is 2 percent of such adjusted gross income;

"(IV) more than $30,000 and not more than $40,000, is 3 percent of such adjusted gross income;

"(V) more than $40,000 and not more than $50,000, is 4 percent of such adjusted gross income;

"(VI) more than $50,000 and not more than $60,000, is 5 percent of such adjusted gross income;

"(VII) more than $60,000 and not more than $70,000, is 6 percent of such adjusted gross income;

"(VIII) more than $70,000 and not more than $80,000, is 7 percent of such adjusted gross income;

"(IX) more than $80,000 and not more than $90,000, is 8 percent of such adjusted gross income;

"(X) more than $90,000 and not more than $100,000, is 9 percent of such adjusted gross income; and

"(XI) more than $100,000, is 10 percent of such adjusted gross income.

"(v) DEPENDENT.—For the purposes of this paragraph, the term 'dependent' means an individual who is a dependent under section 152 of the Internal Revenue Code of 1986.

"(vi) SPECIAL RULE.—In the case of a borrower who is required by the Secretary to provide information to the Secretary to determine the applicable monthly payment of the borrower under this subparagraph, and who does not comply with such requirement, the applicable monthly payment of the borrower shall be—

"(I) the sum of the monthly payment amounts the borrower would have paid for each of the borrower's loans made under this part under a standard repayment plan with a fixed monthly repayment amount, paid over a period of 10 years, based on the outstanding principal due on such loan when such loan entered repayment; and

"(II) determined pursuant to this clause until the date on which the borrower provides such information to the Secretary.".

(e) FEDERAL CONSOLIDATION LOANS.—Section 455(g) of the Higher Education Act of 1965 (20 U.S.C. 1087e(g)) is amended by adding at the end the following new paragraph:

"(3) CONSOLIDATION LOANS MADE ON OR AFTER JULY 1, 2026.—A Federal Direct Consolidation Loan offered to a borrower under this part on or after July 1, 2026, may only be repaid pursuant to a repayment plan described in clause (i) or (ii) of subsection (d)(7)(A) of this section, as applicable, and the repayment schedule of such a Consolidation Loan shall be determined in accordance with such repayment plan.".

(f) INCOME-BASED REPAYMENT.—

(1) AMENDMENTS.—

(A) EXCEPTED CONSOLIDATION LOAN DEFINED.—Section 493C(a)(2) of the Higher Education Act of 1965 (20 U.S.C. 1098e(a)(2)) is amended to read as follows:

"(2) EXCEPTED CONSOLIDATION LOAN.—

"(A) IN GENERAL.—The term 'excepted consolidation loan' means—

"(i) a consolidation loan under section 428C, or a Federal Direct Consolidation Loan, if the proceeds of such loan were used to discharge the liability on an excepted PLUS loan; or

"(ii) a consolidation loan under section 428C, or a Federal Direct Consolidation Loan, if the proceeds of such loan were used to discharge the liability on a consolidation loan under section 428C, or a Federal Direct Consolidation Loan described in clause (i).

"(B) EXCLUSION.—The term 'excepted consolidation loan' does not include a Federal Direct Consolidation Loan described in subparagraph (A) that, on any date during the period beginning on the date of enactment of this subparagraph and ending on June 30, 2028, was being repaid—

"(i) pursuant to the Income Contingent Repayment (ICR) plan in accordance with section 685.209(b) of title 34, Code of Federal Regulations (as in effect on June 30, 2023); or

"(ii) pursuant to another income driven repayment plan.".

(B) TERMINATION OF PARTIAL FINANCIAL HARDSHIP ELIGIBILITY.—Section 493C(a)(3) of the Higher Education Act of 1965 (20 U.S.C. 1098e(a)(3)) is amended to read as follows:

"(3) APPLICABLE AMOUNT.—The term 'applicable amount' means 15 percent of the result obtained by calculating, on at least an annual basis, the amount by which—

"(A) the borrower's, and the borrower's spouse's (if applicable), adjusted gross income; exceeds

"(B) 150 percent of the poverty line applicable to the borrower's family size as determined under section 673(2) of the Community Services Block Grant Act (42 U.S.C. 9902(2)).".

(C) TERMS OF INCOME-BASED REPAYMENT.—Section 493C(b) of the Higher Education Act of 1965 (20 U.S.C. 1098e(b)) is amended—

(i) by amending paragraph (1) to read as follows:

"(1) a borrower of any loan made, insured, or guaranteed under part B or D (other than an excepted PLUS loan or excepted consolidation loan), may elect to have the borrower's aggregate monthly payment for all such loans not exceed the applicable amount divided by 12;";

(ii) by striking paragraph (6) and inserting the following:

"(6) if the monthly payment amount calculated under this section for all loans made to the borrower under part B or D (other than an excepted PLUS loan or excepted consolidation loan) exceeds the monthly amount calculated under section 428(b)(9)(A)(i) or 455(d)(1)(A), based on a 10-year repayment period, when the borrower first made the election described in this subsection (referred to in this paragraph as the 'standard monthly repayment amount'), or if the borrower no longer wishes to continue the election under this subsection, then—

"(A) the maximum monthly payment required to be paid for all loans made to the borrower under part B or D (other than an excepted PLUS loan or excepted consolidation loan) shall be the standard monthly repayment amount; and

"(B) the amount of time the borrower is permitted to repay such loans may exceed 10 years;";

(iii) in paragraph (7)(B)(iv), by inserting "(as such section was in effect on the day before the date of the repeal of section 455(e)" after "section 455(d)(1)(D)"; and

(iv) in paragraph (8), by inserting "or the Repayment Assistance Program under section 455(q)" after "standard repayment plan".

(D) ELIGIBILITY DETERMINATIONS.—Section 493C(c) of the Higher Education Act of 1965 (20 U.S.C. 1098e(c)) is amended to read as follows:

"(c) ELIGIBILITY DETERMINATIONS; AUTOMATIC RECERTIFICATION.—

"(1) IN GENERAL.—The Secretary shall establish procedures for annually determining, in accordance with paragraph (2), the borrower's eligibility for income-based repayment, including the verification of a borrower's annual income and the annual amount due on the total amount of loans made, insured, or guaranteed under part B or D (other than an excepted PLUS loan or excepted consolidation loan), and such other procedures as are necessary to effectively implement income-based repayment under this section. The Secretary shall consider, but is not limited to, the procedures established in accordance with section 455(e)(1) (as in effect on the day before the date of repeal of subsection (e) of section 455) or in connection with income sensitive repayment schedules under section 428(b)(9)(A)(iii) or 428C(b)(1)(E).

"(2) AUTOMATIC RECERTIFICATION.—

"(A) IN GENERAL.—The Secretary shall establish and implement, with respect to any borrower enrolled in an income-based repayment program under this section or under section 455(q), procedures to—

"(i) use return information disclosed under section 6103(l)(13) of the Internal Revenue Code of 1986, pursuant to approval provided under section 494, to determine the repayment obligation of the borrower without further action by the borrower;

"(ii) allow the borrower (or the spouse of the borrower), at any time, to opt out of disclosure under such section 6103(l)(13) and instead provide such information as the Secretary may require to determine the repayment obligation of the borrower (or withdraw from the repayment plan under this section or under section 455(q), as the case may be); and

"(iii) provide the borrower with an opportunity to update the return information so disclosed before the determination of the repayment obligation of the borrower.

"(B) APPLICABILITY.—Subparagraph (A) shall apply to each borrower of a loan eligible to be repaid under this section or under section 455(q), who, on or after the date on which the Secretary establishes procedures under such subparagraph (A)—

"(i) selects, or is required to repay such loan pursuant to, an income-based repayment plan under this section or under section 455(q); or

"(ii) recertifies income or family size under such plan.".

(E) SPECIAL TERMS FOR NEW BORROWERS ON AND AFTER JULY 1, 2014.—Section 493C(e) of the Higher Education Act of 1965 (20 U.S.C. 1098e(e)) is amended—

(i) in the subsection heading, by inserting "AND BEFORE JULY 1, 2026" after "AFTER JULY 1, 2014"; and

(ii) by inserting "and before July 1, 2026" after "after July 1, 2014".

(2) EFFECTIVE DATE AND APPLICATION.—The amendments made by this subsection shall take effect on the date of enactment of this title, and shall apply with respect to any borrower

who is in repayment before, on, or after the date of enactment of this title.

(g) FFEL ADJUSTMENT.—Section 428(b)(9)(A)(v) of the Higher Education Act of 1965 (20 U.S.C. 1078(b)(9)(A)(v)) is amended by striking "who has a partial financial hardship".

SEC. 82002. DEFERMENT; FORBEARANCE.

(a) SUNSET OF ECONOMIC HARDSHIP AND UNEMPLOYMENT DEFERMENTS.—Section 455(f) of the Higher Education Act of 1965 (20 U.S.C. 1087e(f)) is amended—

(1) by striking the subsection heading and inserting the following: "DEFERMENT; FORBEARANCE";

(2) in paragraph (2)—

(A) in subparagraph (B), by striking "not in" and inserting "subject to paragraph (7), not in"; and

(B) in subparagraph (D), by striking "not in" and inserting "subject to paragraph (7), not in"; and

(3) by adding at the end the following:

"(7) SUNSET OF UNEMPLOYMENT AND ECONOMIC HARDSHIP DEFERMENTS.—A borrower who receives a loan made under this part on or after July 1, 2027, shall not be eligible to defer such loan under subparagraph (B) or (D) of paragraph (2).".

(b) FORBEARANCE ON LOANS MADE UNDER THIS PART ON OR AFTER JULY 1, 2027.—Section 455(f) of the Higher Education Act of 1965 (20 U.S.C. 1087e(f)) is amended by adding at the end the following:

"(8) FORBEARANCE ON LOANS MADE UNDER THIS PART ON OR AFTER JULY 1, 2027.—A borrower who receives a loan made under this part on or after July 1, 2027, may only be eligible for a forbearance on such loan pursuant to section 428(c)(3)(B) that does not exceed 9 months during any 24-month period.".

SEC. 82003. LOAN REHABILITATION.

(a) UPDATING LOAN REHABILITATION LIMITS.—

(1) FFEL AND DIRECT LOANS.—Section 428F(a)(5) of the Higher Education Act of 1965 (20 U.S.C. 1078–6(a)(5)) is amended by striking "one time" and inserting "two times".

(2) PERKINS LOANS.—Section 464(h)(1)(D) of the Higher Education Act of 1965 (20 U.S.C. 1087dd(h)(1)(D)) is amended by striking "once" and inserting "twice".

(3) EFFECTIVE DATE.—The amendments made by this subsection shall take effect beginning on July 1, 2027, and shall apply with respect to any loan made, insured, or guaranteed under title IV of the Higher Education Act of 1965 (20 U.S.C. 1070 et seq.).

(b) MINIMUM MONTHLY PAYMENT AMOUNT.—Section 428F(a)(1)(B) of the Higher Education Act of 1965 (20 U.S.C. 1078–6(a)(1)(B)) is amended by adding at the end the following: "With respect to a borrower who has 1 or more loans made under part D on or after July 1, 2027 that are described in subparagraph (A), the total monthly payment of the borrower for all such loans shall not be less than $10.".

SEC. 82004. PUBLIC SERVICE LOAN FORGIVENESS.

Section 455(m)(1)(A) of the Higher Education Act of 1965 (20 U.S.C. 1087e(m)(1)(A)) is amended—

(1) in clause (iii), by striking "; or" and inserting a semicolon;

(2) in clause (iv), by striking "; and" and inserting "(as in effect on the day before the date of the repeal of subsection (e) of this section); or"; and

(3) by adding at the end the following new clause:

"(v) on-time payments under the Repayment Assistance Plan under subsection (q); and".

SEC. 82005. STUDENT LOAN SERVICING.

Paragraph (1) of section 458(a) of the Higher Education Act of 1965 (20 U.S.C. 1087h(a)(1)) is amended to read as follows:

"(1) ADDITIONAL MANDATORY FUNDS FOR SERVICING.—There shall be available to the Secretary (in addition to any other amounts appropriated under any appropriations Act for administrative costs under this part and part B and out of any money in the Treasury not otherwise appropriated) $1,000,000,000 to be obligated for administrative costs under this part and part B, including the costs of servicing the direct student loan programs under this part, which shall remain available until expended.".

Subtitle D—Pell Grants

SEC. 83001. ELIGIBILITY.

(a) FOREIGN INCOME AND FEDERAL PELL GRANT ELIGIBILITY.—

(1) ADJUSTED GROSS INCOME DEFINED.—Section 401(a)(2)(A) of the Higher Education Act of 1965 (20 U.S.C. 1070a(a)(2)(A)) is amended to read as follows:

"(A) the term 'adjusted gross income' means—

"(i) in the case of a dependent student, for the second tax year preceding the academic year—

"(I) the adjusted gross income (as defined in section 62 of the Internal Revenue Code of 1986) of the student's parents; plus

"(II) for Federal Pell Grant determinations made for academic years beginning on or after July 1, 2026, the foreign income (as described in section 480(b)(5)) of the student's parents; and

"(ii) in the case of an independent student, for the second tax year preceding the academic year—

"(I) the adjusted gross income (as defined in section 62 of the Internal Revenue Code of 1986) of the student (and the student's spouse, if applicable); plus

"(II) for Federal Pell Grant determinations made for academic years beginning on or after July 1, 2026, the foreign income (as described in section 480(b)(5)) of the student (and the student's spouse, if applicable);".

(2) SUNSET.—Section 401(b)(1)(D) of the Higher Education Act of 1965 (20 U.S.C. 1070a(b)(1)(D)) is amended—

(A) by striking "A student" and inserting "For each academic year beginning before July 1, 2026, a student"; and

(B) by inserting ", as in effect for such academic year," after "section 479A(b)(1)(B)(v)".

(3) CONFORMING AMENDMENTS.—

(A) IN GENERAL.—Section 479A(b)(1)(B) of the Higher Education Act of 1965 (20 U.S.C. 1087tt(b)(1)(B)) is amended—

(i) by striking clause (v); and

(ii) by redesignating clauses (vi) and (vii) as clauses (v) and (vi), respectively.

(B) EFFECTIVE DATE.—The amendment made by subparagraph (A) shall take effect on July 1, 2026.

(b) FEDERAL PELL GRANT INELIGIBILITY DUE TO A HIGH STUDENT AID INDEX.—

(1) IN GENERAL.—Section 401(b)(1) of the Higher Education Act of 1965 (20 U.S.C. 1070a(b)(1)) is amended by adding at the end the following:

"(F) INELIGIBILITY OF STUDENTS WITH A HIGH STUDENT AID INDEX.—Notwithstanding subparagraphs (A) through (E), a student shall not be eligible for a Federal Pell Grant under this subsection for an academic year in which the student has a student aid index that equals or exceeds twice the amount of the total maximum Federal Pell Grant for such academic year.".

(2) EFFECTIVE DATE.—The amendment made by paragraph (1) shall take effect on July 1, 2026.

SEC. 83002. WORKFORCE PELL GRANTS.

(a) IN GENERAL.—Section 401 of the Higher Education Act of 1965 (20 U.S.C. 1070a) is amended by adding at the end the following:

"(k) WORKFORCE PELL GRANT PROGRAM.—

"(1) IN GENERAL.—For the award year beginning on July 1, 2026, and each subsequent award year, the Secretary shall award grants (to be known as 'Workforce Pell Grants') to eligible students under paragraph (2) in accordance with this subsection.

"(2) ELIGIBLE STUDENTS.—To be eligible to receive a Workforce Pell Grant under this subsection for any period of enrollment, a student shall meet the eligibility requirements for a Federal Pell Grant under this section, except that the student—

"(A) shall be enrolled, or accepted for enrollment, in an eligible program under section 481(b)(3) (hereinafter referred to as an 'eligible workforce program'); and

"(B) may not—

"(i) be enrolled, or accepted for enrollment, in a program of study that leads to a graduate credential; or

"(ii) have attained such a credential.

"(3) TERMS AND CONDITIONS OF AWARDS.—The Secretary shall award Workforce Pell Grants under this subsection in the same manner and with the same terms and conditions as the Secretary awards Federal Pell Grants under this section, except that—

"(A) each use of the term 'eligible program' (except in subsection (b)(9)(A)) shall be substituted by 'eligible workforce program under section 481(b)(3)';

"(B) the provisions of subsection (d)(2) shall not be applicable to eligible workforce programs; and

"(C) a student who is eligible for a grant equal to less than the amount of the minimum Federal Pell Grant because the eligible workforce program in which the student is enrolled or accepted for enrollment is less than an academic year (in hours of instruction or weeks of duration) may still be eligible for a Workforce Pell Grant in an amount that is prorated based on the length of the program.

"(4) PREVENTION OF DOUBLE BENEFITS.—No eligible student described in paragraph (2) may concurrently receive a grant under both this subsection and—

"(A) subsection (b); or

"(B) subsection (c).

"(5) DURATION LIMIT.—Any period of study covered by a Workforce Pell Grant awarded under this subsection shall be included in determining a student's duration limit under subsection (d)(5).".

(b) PROGRAM ELIGIBILITY FOR WORKFORCE PELL GRANTS.—Section 481(b) of the Higher Education Act of 1965 (20 U.S.C. 1088(b)) is amended—

(1) by redesignating paragraphs (3) and (4) as paragraphs (4) and (5), respectively; and

(2) by inserting after paragraph (2) the following:

"(3)(A) A program is an eligible program for purposes of the Workforce Pell Grant program under section 401(k) only if—

"(i) it is a program of at least 150 clock hours of instruction, but less than 600 clock hours of instruction, or an equivalent number of credit hours, offered by an eligible institution during a minimum of 8 weeks, but less than 15 weeks;

"(ii) it is not offered as a correspondence course, as defined in 600.2 of title 34, Code of Federal Regulations (as in effect on July 1, 2021);

"(iii) the Governor of a State, after consultation with the State board, determines that the program—

"(I) provides an education aligned with the requirements of high-skill, high-wage (as identified by the State pursuant to section 122 of the Carl D. Perkins Career and Technical Education Act (20 U.S.C. 2342)), or in-demand industry sectors or occupations;

"(II) meets the hiring requirements of potential employers in the sectors or occupations described in subclause (I);

"(III) either—

"(aa) leads to a recognized postsecondary credential that is stackable and portable across more than one employer; or

"(bb) with respect to students enrolled in the program—

"(AA) prepares such students for employment in an occupation for which there is only one recognized postsecondary credential; and

"(BB) provides such students with such a credential upon completion of such program; and

"(IV) prepares students to pursue 1 or more certificate or degree programs at 1 or more institutions of higher education (which may include the eligible institution providing the program), including by ensuring—

"(aa) that a student, upon completion of the program and enrollment in such a related certificate or degree program, will receive academic credit for the Workforce Pell program that will be accepted toward meeting such certificate or degree program requirements; and

"(bb) the acceptability of such credit toward meeting such certificate or degree program requirements; and

"(iv) after the Governor of such State makes the determination that the program meets the requirements under clause (iii), the Secretary determines that—

"(I) the program has been offered by the eligible institution for not less than 1 year prior to the date on which the Secretary makes a determination under this clause;

"(II) for each award year, the program has a verified completion rate of at least 70 percent, within 150 percent of the normal time for completion;

"(III) for each award year, the program has a verified job placement rate of at least 70 percent, measured 180 days after completion; and

"(IV) for each award year, the total amount of the published tuition and fees of the program for such year is an amount that does not exceed the value-added earnings of students who received Federal financial aid under this title and who completed the program 3 years prior to the award year, as such earnings are determined by calculating the difference between—

"(aa) the median earnings of such students, as adjusted by the State and metropolitan area regional price parities of the Bureau of Economic Analysis based on the location of such program; and

"(bb) 150 percent of the poverty line applicable to a single individual as determined under section 673(2) of the Community Services Block Grant Act (42 U.S.C. 9902(2)) for such year.

"(B) In this paragraph:

"(i) The term 'eligible institution' means an eligible institution for purposes of section 401.

"(ii) The term 'Governor' means the chief executive of a State.

"(iii) The terms 'in-demand industry sector or occupation', 'recognized postsecondary credential', and 'State board' have the meanings given such terms in section 3 of the Workforce Innovation and Opportunity Act.".

(c) EFFECTIVE DATE; APPLICABILITY.—The amendments made by this section shall take effect on July 1, 2026, and shall apply with respect to award year 2026–2027 and each succeeding award year.

SEC. 83003. PELL SHORTFALL.

Section 401(b)(7)(A)(iii) of the Higher Education Act of 1965 (20 U.S.C. 1070a(b)(7)(A)(iii)) is amended by striking "$2,170,000,000" and inserting "$12,670,000,000".

SEC. 83004. FEDERAL PELL GRANT EXCLUSION RELATING TO OTHER GRANT AID.

Section 401(d) of the Higher Education Act of 1965 (20 U.S.C. 1070a(d)) is amended by adding at the end the following:

"(6) EXCLUSION.—Beginning on July 1, 2026, and notwithstanding this subsection or subsection (b), a student shall not be eligible for a Federal Pell Grant under subsection (b) during any period for which the student receives grant aid from non-Federal sources, including States, institutions of higher education, or private sources, in an amount that equals or exceeds the student's cost of attendance for such period.".

Subtitle E—Accountability

SEC. 84001. INELIGIBILITY BASED ON LOW EARNING OUTCOMES.

Section 454 of the Higher Education Act of 1965 (20 U.S.C. 1087d) is amended—

(1) in subsection (a)—

(A) in paragraph (5), by striking "and" after the semicolon;

(B) by redesignating paragraph (6) as paragraph (7); and

(C) by inserting after paragraph (5) the following:

"(6) provide assurances that, beginning July 1, 2026, the institution will comply with all requirements of subsection (c); and";

(2) in subsection (b)(2), by striking "and (6)" and inserting "(6), and (7)";

(3) by redesignating subsection (c) as subsection (d); and

(4) by inserting after subsection (b) the following:

"(c) INELIGIBILITY FOR CERTAIN PROGRAMS BASED ON LOW EARNING OUTCOMES.—

"(1) IN GENERAL.—Notwithstanding section 481(b), an institution of higher education subject to this subsection shall not use funds under this part for student enrollment in an educational program offered by the institution that is described in paragraph (2).

"(2) LOW-EARNING OUTCOME PROGRAMS DESCRIBED.—An educational program at an institution is described in this paragraph if the program awards an undergraduate degree, graduate or professional degree, or graduate certificate, for which the median earnings (as determined by the Secretary) of the programmatic cohort of students who received funds under this title for enrollment in such program, who completed such program during the academic year that is 4 years before the year of the determination, who are not enrolled in any institution of higher education, and who are working, are, for not less than 2 of the 3 years immediately preceding the date of the determination, less than the median earnings of a working adult described in paragraph (3) for the corresponding year.

"(3) CALCULATION OF MEDIAN EARNINGS.—

"(A) WORKING ADULT.—For purposes of applying paragraph (2) to an educational program at an institution, a working adult described in this paragraph is a working adult who, for the corresponding year—

"(i) is aged 25 to 34;

"(ii) is not enrolled in an institution of higher education; and

"(iii)(I) in the case of a determination made for an educational program that awards a baccalaureate or lesser degree, has only a high school diploma or its recognized equivalent; or

"(II) in the case of a determination made for a graduate or professional program, has only a baccalaureate degree.

"(B) SOURCE OF DATA.—For purposes of applying paragraph (2) to an educational program at an institution, the median earnings of a working adult, as described in subparagraph (A), shall be based on data from the Bureau of the Census—

"(i) with respect to an educational program that awards a baccalaureate or lesser degree—

"(I) for the State in which the institution is located; or

"(II) if fewer than 50 percent of the students enrolled in the institution reside in the State where the institution is located, for the entire United States; and

"(ii) with respect to an educational program that is a graduate or professional program—

"(I) for the lowest median earnings of—

"(aa) a working adult in the State in which the institution is located;

"(bb) a working adult in the same field of study (as determined by the Secretary, such as by using the 2-digit CIP code) in the State in which the institution is located; and

"(cc) a working adult in the same field of study (as so determined) in the entire United States; or

"(II) if fewer than 50 percent of the students enrolled in the institution reside in the State where the institution is located, for the lower median earnings of—

"(aa) a working adult in the entire United States; or

"(bb) a working adult in the same field of study (as so determined) in the entire United States.

"(4) SMALL PROGRAMMATIC COHORTS.—For any year for which the programmatic cohort described in paragraph (2) for an educational program of an institution is fewer than 30 individuals, the Secretary shall—

"(A) first, aggregate additional years of programmatic data in order to achieve a cohort of at least 30 individuals; and

"(B) second, in cases in which the cohort (including the individuals added under subparagraph (A)) is still fewer than 30 individuals, aggregate additional cohort years of programmatic data for educational programs of equivalent length in order to achieve a cohort of at least 30 individuals.

"(5) APPEALS PROCESS.—An educational program shall not lose eligibility under this subsection unless the institution has had the opportunity to appeal the programmatic median earnings of students working and not enrolled determination under paragraph (2), through a process established by the Secretary. During such appeal, the Secretary may permit the educational program to continue to participate in the program under this part.

"(6) NOTICE TO STUDENTS.—

"(A) IN GENERAL.—If an educational program of an institution of higher education subject to this subsection does not meet the cohort median earning requirements, as described in paragraph (2), for one year during the applicable covered period but has not yet failed to meet such requirements for 2 years during such covered period, the institution shall promptly inform each student enrolled in the educational program of the eligible program's low cohort median earnings and that the educational program is at risk of losing its eligibility for funds under this part.

"(B) COVERED PERIOD.—In this paragraph, the term 'covered period' means the period of the 3 years immediately preceding the date of a determination made under paragraph (2).

"(7) REGAINING PROGRAMMATIC ELIGIBILITY.—The Secretary shall establish a process by which an institution of higher education that has an educational program that has lost eligibility under this subsection may, after a period of not less than 2 years of such program's ineligibility, apply to regain such eligibility, subject to the requirements established by the Secretary that further the purpose of this subsection.".

Subtitle F—Regulatory Relief

SEC. 85001. DELAY OF RULE RELATING TO BORROWER DEFENSE TO REPAYMENT.

(a) DELAY.—Beginning on the date of enactment of this section, for loans that first originate before July 1, 2035, the provisions of subpart D of part 685 of title 34, Code of Federal Regulations (relating to borrower defense to repayment), as added or amended by the final regulations published by the Department of Education on November 1, 2022, and titled "Institutional Eligibility Under the Higher Education Act of 1965, as Amended; Student Assistance General Provisions; Federal Perkins Loan Program; Federal Family Education Loan Program; and William D. Ford Federal Direct Loan Program" (87 Fed. Reg. 65904) shall not be in effect.

(b) EFFECT.—Beginning on the date of enactment of this section, with respect to loans that first originate before July 1, 2035, any regulations relating to borrower defense to repayment that took effect on July 1, 2020, are restored and revived as such regulations were in effect on such date.

SEC. 85002. DELAY OF RULE RELATING TO CLOSED SCHOOL DISCHARGES.

(a) DELAY.—Beginning on the date of enactment of this section, for loans that first originate before July 1, 2035, the provisions of sections 674.33(g), 682.402(d), and 685.214 of title 34, Code of Federal Regulations (relating to closed school discharges), as added or amended by the final regulations published by the Department of Education on November 1, 2022, and titled "Institutional Eligibility Under the Higher Education Act of 1965, as Amended; Student Assistance General Provisions; Federal Perkins Loan Program; Federal Family Education Loan Program; and William D. Ford Federal Direct Loan Program" (87 Fed. Reg. 65904), shall not be in effect.

(b) EFFECT.—Beginning on the date of enactment of this section, with respect to loans that first originate before July 1, 2035, the portions of the Code of Federal Regulations described in subsection (a) and amended by the final regulations described in subsection (a) shall be in effect as if the amendments made by such final regulations had not been made.

Subtitle G—Garden of Heroes

SEC. 86001. GARDEN OF HEROES.

In addition to amounts otherwise available, there are appropriated to the National Endowment for the Humanities for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available through fiscal year 2028, $40,000,000 for the procurement of statues as described in Executive Order 13934 (85 Fed. Reg. 41165; relating to building and rebuilding monuments to American heroes), Executive Order 13978 (86 Fed. Reg. 6809; relating to building the National Garden of American Heroes), and Executive Order 14189 (90 Fed. Reg. 8849; relating to celebrating America's birthday).

Subtitle H—Office of Refugee Resettlement

SEC. 87001. POTENTIAL SPONSOR VETTING FOR UNACCOMPANIED ALIEN CHILDREN APPROPRIATION.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Office of Refugee Resettlement for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $300,000,000, to remain available until September 30, 2028, for the purposes described in subsection (b).

(b) USE OF FUNDS.—The funds made available under subsection (a) may only be used for the Office of Refugee Resettlement to support costs associated with—

(1) background checks on potential sponsors, which shall include—

(A) the name of the potential sponsor and of all adult residents of the potential sponsor's household;

(B) the social security number or tax payer identification number of the potential sponsor and of all adult residents of the potential sponsor's household;

(C) the date of birth of the potential sponsor and of all adult residents of the potential sponsor's household;

(D) the validated location of the residence at which the unaccompanied alien child will be placed;

(E) an in-person or virtual interview with, and suitability study concerning, the potential sponsor and all adult residents of the potential sponsor's household;

(F) contact information for the potential sponsor and for all adult residents of the potential sponsor's household; and

(G) the results of all background and criminal records checks for the potential sponsor and for all adult residents of the potential sponsor's household, which shall include, at a minimum, an investigation of the public records sex offender registry, a public records background check, and a national criminal history check based on fingerprints;

(2) home studies of potential sponsors of unaccompanied alien children;

(3) determining whether an unaccompanied alien child poses a danger to self or others by conducting an examination of the unaccompanied alien child for gang-related tattoos and other gang-related markings and covering such tattoos or markings while the child is in the care of the Office of Refugee Resettlement;

(4) data systems improvement and sharing that supports the health, safety, and well being of unaccompanied alien children by determining the appropriateness of potential sponsors of unaccompanied alien children and of adults residing in the household of the potential sponsor and by assisting with the identification and investigation of child labor exploitation and child trafficking; and

(5) coordinating and communicating with State child welfare agencies regarding the placement of unaccompanied alien children in such States by the Office of Refugee Resettlement.

(c) DEFINITIONS.—In this section:

(1) POTENTIAL SPONSOR.—The term "potential sponsor" means an individual or entity who applies for the custody of an unaccompanied alien child.

(2) UNACCOMPANIED ALIEN CHILD.—The term "unaccompanied alien child" has the meaning given such term in section 462(g) of the Homeland Security Act of 2002 (6 U.S.C. 279(g)).

TITLE IX—COMMITTEE ON HOMELAND SECURITY AND GOVERNMENTAL AFFAIRS

Subtitle A—Homeland Security Provisions

SEC. 90001. BORDER INFRASTRUCTURE AND WALL SYSTEM.

In addition to amounts otherwise available, there is appropriated to the Commissioner of U.S. Customs and Border Protection for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $46,550,000,000 for necessary expenses relating to the following elements of the border infrastructure and wall system:

(1) Construction, installation, or improvement of new or replacement primary, waterborne, and secondary barriers.

(2) Access roads.

(3) Barrier system attributes, including cameras, lights, sensors, and other detection technology.

(4) Any work necessary to prepare the ground at or near the border to allow U.S. Customs and Border Protection to conduct its operations, including the construction and maintenance of the barrier system.

SEC. 90002. U.S. CUSTOMS AND BORDER PROTECTION PERSONNEL, FLEET VEHICLES, AND FACILITIES.

(a) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Commissioner of U.S. Customs and Border Protection for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, the following:

(1) PERSONNEL.—$4,100,000,000, to remain available until September 30, 2029, to hire and train additional Border Patrol agents, Office of Field Operations officers, Air and Marine agents, rehired annuitants, and U.S. Customs and Border Protection field support personnel.

(2) RETENTION, HIRING, AND PERFORMANCE BONUSES.—$2,052,630,000, to remain available until September 30, 2029, to provide recruitment bonuses, performance awards, or annual retention bonuses to eligible Border Patrol agents, Office of Field Operations officers, and Air and Marine agents.

(3) VEHICLES.—$855,000,000, to remain available until September 30, 2029, for the repair of existing patrol units and the lease or acquisition of additional patrol units.

(4) FACILITIES.—$5,000,000,000 for necessary expenses relating to lease, acquisition, construction, design, or improvement of facilities and checkpoints owned, leased, or operated by U.S. Customs and Border Protection.

(b) RESTRICTION.—None of the funds made available by subsection (a) may be used to recruit, hire, or train personnel for the duties of processing coordinators after October 31, 2028.

SEC. 90003. DETENTION CAPACITY.

(a) IN GENERAL.—In addition to any amounts otherwise appropriated, there is appropriated to U.S. Immigration and Customs Enforcement for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $45,000,000,000, for single adult alien detention capacity and family residential center capacity.

(b) DURATION AND STANDARDS.—Aliens may be detained at family residential centers, as described in subsection (a), pending a decision, under the Immigration and Nationality Act (8 U.S.C. 1101 et seq.), on whether the aliens are to be removed from the United States and, if such aliens are ordered removed from the United States, until such aliens are removed. The detention standards for the single adult detention capacity described in subsection (a) shall be set in the discretion of the Secretary of Homeland Security, consistent with applicable law.

(c) DEFINITION OF FAMILY RESIDENTIAL CENTER.—In this section, the term "family residential center" means a facility used by the Department of Homeland Security to detain family units of aliens (including alien children who are not unaccompanied alien children (as defined in section 462(g) of the Homeland Security

Act of 2002 (6 U.S.C. 279(g)))) who are encountered or apprehended by the Department of Homeland Security.

SEC. 90004. BORDER SECURITY, TECHNOLOGY, AND SCREENING.

(a) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Commissioner of U.S. Customs and Border Protection for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, $6,168,000,000 for the following:

(1) Procurement and integration of new nonintrusive inspection equipment and associated civil works, including artificial intelligence, machine learning, and other innovative technologies, as well as other mission support, to combat the entry or exit of illicit narcotics at ports of entry and along the southwest, northern, and maritime borders.

(2) Air and Marine operations' upgrading and procurement of new platforms for rapid air and marine response capabilities.

(3) Upgrades and procurement of border surveillance technologies along the southwest, northern, and maritime borders.

(4) Necessary expenses, including the deployment of technology, relating to the biometric entry and exit system under section 7208 of the Intelligence Reform and Terrorism Prevention Act of 2004 (8 U.S.C. 1365b).

(5) Screening persons entering or exiting the United States.

(6) Initial screenings of unaccompanied alien children (as defined in section 462(g) of the Homeland Security Act of 2002 (6 U.S.C. 279(g))), consistent with the William Wilberforce Trafficking Victims Protection Reauthorization Act of 2008 (Public Law 110–457; 122 Stat. 5044).

(7) Enhancing border security by combating drug trafficking, including fentanyl and its precursor chemicals, at the southwest, northern, and maritime borders.

(8) Commemorating efforts and events related to border security.

(b) RESTRICTIONS.—None of the funds made available under subsection (a) may be used for the procurement or deployment of surveillance towers along the southwest border and northern border that have not been tested and accepted by U.S. Customs and Border Protection to deliver autonomous capabilities.

(c) DEFINITION OF AUTONOMOUS.—In this section, with respect to capabilities, the term "autonomous" means a system designed to apply artificial intelligence, machine learning, computer vision, or other algorithms to accurately detect, identify, classify, and track items of interest in real time such that the system can make operational adjustments without the active engagement of personnel or continuous human command or control.

SEC. 90005. STATE AND LOCAL ASSISTANCE.

(a) STATE HOMELAND SECURITY GRANT PROGRAMS.—

(1) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Administrator of the Federal Emergency Management Agency for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to remain available until September 30, 2029, to be administered under the State Homeland Security Grant Program authorized under section 2004 of the Homeland Security Act of 2002 (6 U.S.C. 605), to enhance State, local, and Tribal security through grants, contracts, cooperative agreements, and other activities—

(A) $500,000,000 for State and local capabilities to detect, identify, track, or monitor threats from unmanned aircraft systems (as such term is defined in section 44801 of title 49, United States Code), consistent with titles 18 and 49 of the United States Code;

(B) $625,000,000 for security and other costs related to the 2026 FIFA World Cup;

(C) $1,000,000,000 for security, planning, and other costs related to the 2028 Olympics; and

(D) $450,000,000 for the Operation Stonegarden Grant Program.

(2) TERMS AND CONDITIONS.—None of the funds made available under subparagraph (B) or (C) of paragraph (1) shall be subject to the requirements of section 2004(e)(1) or section 2008(a)(12) of the Homeland Security Act of 2002 (6 U.S.C. 605(e)(1), 609(a)(12)).

(b) STATE BORDER SECURITY REINFORCEMENT FUND.—

(1) ESTABLISHMENT.—There is established, in the Department of Homeland Security, a fund to be known as the "State Border Security Reinforcement Fund."

(2) PURPOSES.—The Secretary of Homeland Security shall use amounts appropriated or otherwise made available for the Fund for grants to eligible States and units of local government for any of the following purposes:

(A) Construction or installation of a border wall, border fencing or other barrier, or buoys along the southern border of the United States, which may include planning, procurement of materials, and personnel costs related to such construction or installation.

(B) Any work necessary to prepare the ground at or near land borders to allow construction and maintenance of a border wall or other barrier fencing.

(C) Detection and interdiction of illicit substances and aliens who have unlawfully entered the United States and have committed a crime under Federal, State, or local law, and transfer or referral of such aliens to the Department of Homeland Security as provided by law.

(D) Relocation of aliens who are unlawfully present in the United States from small population centers to other domestic locations.

(3) APPROPRIATION.—In addition to amounts otherwise available for the purposes described in paragraph (2), there is appropriated for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, to the Department of Homeland Security for the State Border Security Reinforcement Fund established by paragraph (1), $10,000,000,000, to remain available until September 30, 2034, for qualified expenses for such purposes.

(4) ELIGIBILITY.—The Secretary of Homeland Security may provide grants from the fund established by paragraph (1) to State agencies and units of local governments for expenditures made for completed, ongoing, or new activities, in accordance with law, that occurred on or after January 20, 2021.

(5) APPLICATION.—Each State desiring to apply for a grant under this subsection shall submit an application to the Secretary containing such information in support of the application as the Secretary may require. The Secretary shall require that

each State include in its application the purposes for which the State seeks the funds and a description of how the State plans to allocate the funds. The Secretary shall begin to accept applications not later than 90 days after the date of the enactment of this Act.

(6) TERMS AND CONDITIONS.—Nothing in this subsection shall authorize any State or local government to exercise immigration or border security authorities reserved exclusively to the Federal Government under the Immigration and Nationality Act (8 U.S.C. 1101 et seq.) or the Homeland Security Act of 2002 (6 U.S.C. 101 et seq.). The Federal Emergency Management Agency may use not more than 1 percent of the funds made available under this subsection for the purpose of administering grants provided for in this section.

SEC. 90006. PRESIDENTIAL RESIDENCE PROTECTION.

(a) IN GENERAL.—In addition to amounts otherwise available, there is appropriated to the Administrator of the Federal Emergency Management Agency for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $300,000,000, to remain available until September 30, 2029, for the reimbursement of extraordinary law enforcement personnel costs for protection activities directly and demonstrably associated with any residence of the President designated pursuant to section 3 or 4 of the Presidential Protection Assistance Act of 1976 (Public Law 94–524; 18 U.S.C. 3056 note) to be secured by the United States Secret Service.

(b) AVAILABILITY.—Funds appropriated under this section shall be available only for costs that a State or local agency—

(1) incurred or incurs on or after July 1, 2024;

(2) demonstrates to the Administrator of the Federal Emergency Management Agency as being—

(A) in excess of typical law enforcement operation costs;

(B) directly attributable to the provision of protection described in this section; and

(C) associated with a nongovernmental property designated pursuant to section 3 or 4 of the Presidential Protection Assistance Act of 1976 (Public Law 94–524; 18 U.S.C. 3056 note) to be secured by the United States Secret Service; and

(3) certifies to the Administrator as compensating protection activities requested by the United States Secret Service.

(c) TERMS AND CONDITIONS.—The Federal Emergency Management Agency may use not more than 3 percent of the funds made available under this section for the purpose of administering grants provided for in this section.

SEC. 90007. DEPARTMENT OF HOMELAND SECURITY APPROPRIATIONS FOR BORDER SUPPORT.

In addition to amounts otherwise available, there are appropriated to the Secretary of Homeland Security for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $10,000,000,000, to remain available until September 30, 2029, for reimbursement of costs incurred in undertaking activities in support of the Department of Homeland Security's mission to safeguard the borders of the United States.

Subtitle B—Governmental Affairs Provisions

SEC. 90101. FEHB IMPROVEMENTS.

(a) SHORT TITLE.—This section may be cited as the "FEHB Protection Act of 2025".

(b) DEFINITIONS.—In this section:

(1) DIRECTOR.—The term "Director" means the Director of the Office of Personnel Management.

(2) HEALTH BENEFITS PLAN; MEMBER OF FAMILY.—The terms "health benefits plan" and "member of family" have the meanings given those terms in section 8901 of title 5, United States Code.

(3) OPEN SEASON.—The term "open season" means an open season described in section 890.301(f) of title 5, Code of Federal Regulations, or any successor regulation.

(4) PROGRAM.—The term "Program" means the health insurance programs carried out under chapter 89 of title 5, United States Code, including the program carried out under section 8903c of that title.

(5) QUALIFYING LIFE EVENT.—The term "qualifying life event" has the meaning given the term in section 892.101 of title 5, Code of Federal Regulations, or any successor regulation.

(c) VERIFICATION REQUIREMENTS.—Not later than 1 year after the date of enactment of this Act, the Director shall issue regulations and implement a process to verify—

(1) the veracity of any qualifying life event through which an enrollee in the Program seeks to add a member of family with respect to the enrollee to a health benefits plan under the Program; and

(2) that, when an enrollee in the Program seeks to add a member of family with respect to the enrollee to the health benefits plan of the enrollee under the Program, including during any open season, the individual so added is a qualifying member of family with respect to the enrollee.

(d) FRAUD RISK ASSESSMENT.—In any fraud risk assessment conducted with respect to the Program on or after the date of enactment of this Act, the Director shall include an assessment of individuals who are enrolled in, or covered under, a health benefits plan under the Program even though those individuals are not eligible to be so enrolled or covered.

(e) FAMILY MEMBER ELIGIBILITY VERIFICATION AUDIT.—

(1) IN GENERAL.—During the 3-year period beginning on the date that is 1 year after the date of enactment of this Act, the Director shall carry out a comprehensive audit regarding members of family who are covered under an enrollment in a health benefits plan under the Program.

(2) CONTENTS.—With respect to the audit carried out under paragraph (1), the Director shall review marriage certificates, birth certificates, and other appropriate documents that are necessary to determine eligibility to enroll in a health benefits plan under the Program.

(f) DISENROLLMENT OR REMOVAL.—Not later than 180 days after the date of enactment of this Act, the Director shall develop a process by which any individual enrolled in, or covered under, a health benefits plan under the Program who is not eligible to be so enrolled or covered shall be disenrolled or removed from enrollment in, or coverage under, that health benefits plan.

(g) EARNED BENEFITS AND HEALTH CARE ADMINISTRATIVE SERVICES ASSOCIATED OVERSIGHT AND AUDIT FUNDING.—Section 8909 of title 5, United States Code, is amended—

(1) in subsection (a)(2), by inserting before the period at the end the following: ", except that the amounts required to be set aside under subsection (b)(2) shall not be subject to the limitations that may be specified annually by Congress"; and

(2) in subsection (b)—

(A) by redesignating paragraph (2) as paragraph (3); and

(B) by inserting after paragraph (1) the following:

"(2) In fiscal year 2026, $66,000,000, to be derived from all contributions, and to remain available until the end of fiscal year 2035, for the Director of the Office to carry out subsections (c) through (f) of the FEHB Protection Act of 2025.".

SEC. 90102. PANDEMIC RESPONSE ACCOUNTABILITY COMMITTEE.

(a) PANDEMIC RESPONSE ACCOUNTABILITY COMMITTEE FUNDING AVAILABILITY.—In addition to amounts otherwise available, there is appropriated for fiscal year 2026, out of any money in the Treasury not otherwise appropriated, $88,000,000, to remain available until expended, for the Pandemic Response Accountability Committee to support oversight of the Coronavirus response and of funds provided in this Act or any other Act pertaining to the Coronavirus pandemic.

(b) CARES ACT.—Section 15010 of the CARES Act (Public Law 116–136; 134 Stat. 533) is amended—

(1) in subsection (a)(6)—

(A) in subparagraph (E), by striking "or" at the end;

(B) in subparagraph (F), by striking "and" at the end and inserting "or"; and

(C) by adding at the end the following:

"(G) the Act titled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14'; and"; and

(2) in subsection (k), by striking "2025" and inserting "2034".

SEC. 90103. APPROPRIATION FOR THE OFFICE OF MANAGEMENT AND BUDGET.

In addition to amounts otherwise available, there is appropriated to the Office of Management and Budget for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $100,000,000, to remain available until September 30, 2029, for purposes of finding budget and accounting efficiencies in the executive branch.

TITLE X—COMMITTEE ON THE JUDICIARY

Subtitle A—Immigration and Law Enforcement Matters

PART I—IMMIGRATION FEES

SEC. 100001. APPLICABILITY OF THE IMMIGRATION LAWS.

(a) APPLICABILITY.—The fees under this subtitle shall apply to aliens in the circumstances described in this subtitle.

(b) TERMS.—The terms used under this subtitle shall have the meanings given such terms in section 101 of the Immigration and Nationality Act (8 U.S.C. 1101).

(c) REFERENCES TO IMMIGRATION AND NATIONALITY ACT.—Except as otherwise expressly provided, any reference in this subtitle to a section or other provision shall be considered to be to a section or other provision of the Immigration and Nationality Act (8 U.S.C. 1101 et seq.).

SEC. 100002. ASYLUM FEE.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security or the Attorney General, as applicable, shall require the payment of a fee, equal to the amount specified in this section, by any alien who files an application for asylum under section 208 (8 U.S.C. 1158) at the time such application is filed.

(b) INITIAL AMOUNT.—During fiscal year 2025, the amount specified in this section shall be the greater of—

(1) $100; or

(2) such amount as the Secretary or the Attorney General, as applicable, may establish, by rule.

(c) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(1) the amount of the fee required under this section for the most recently concluded fiscal year; and

(2) the product resulting from the multiplication of the amount referred to in paragraph (1) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(d) DISPOSITION OF ASYLUM FEE PROCEEDS.—During each fiscal year—

(1) 50 percent of the fees received from aliens filing applications with the Attorney General—

(A) shall be credited to the Executive Office for Immigration Review; and

(B) may be retained and expended without further appropriation;

(2) 50 percent of fees received from aliens filing applications with the Secretary of Homeland Security—

(A) shall be credited to U.S. Citizenship and Immigration Services;

(B) shall be deposited into the Immigration Examinations Fee Account established under section 286(m) (8 U.S.C. 1356(m)); and

(C) may be retained and expended without further appropriation; and

(3) any amounts received in fees required under this section that were not credited to the Executive Office for Immigration Review pursuant to paragraph (1) or to U.S. Citizenship and Immigration Services pursuant to paragraph (2) shall be deposited into the general fund of the Treasury.

(e) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100003. EMPLOYMENT AUTHORIZATION DOCUMENT FEES.

(a) ASYLUM APPLICANTS.—

(1) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this subsection, by any alien who files an initial application for employment authorization under section 208(d)(2) (8 U.S.C. 1158(d)(2)) at the time such initial employment authorization application is filed.

(2) INITIAL AMOUNT.—During fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $550; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(3) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this section for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(4) DISPOSITION OF EMPLOYMENT AUTHORIZATION DOCUMENT FEES.—During each fiscal year—

(A) 25 percent of the fees collected pursuant to this subsection—

(i) shall be credited to U.S. Citizenship and Immigration Services;

(ii) shall be deposited into the Immigration Examinations Fee Account established under section 286(m) (8 U.S.C. 1356(m)); and

(iii) may be retained and expended by U.S. Citizenship and Immigration Services without further appropriation, provided that not less than 50 percent is used to detect and prevent immigration benefit fraud; and

(B) any amounts collected pursuant to this subsection that are not credited to U.S. Citizenship and Immigration Services pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(5) NO FEE WAIVER.—Fees required to be paid under this subsection shall not be waived or reduced.

(b) PAROLEES.—

(1) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this subsection, by any alien paroled into the United States for any initial application for employment authorization at the time such initial application is filed. Each initial employment authorization shall be valid for a period of 1 year or for the duration of the alien's parole, whichever is shorter.

(2) INITIAL AMOUNT.—During fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $550; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(3) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this subsection shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(4) DISPOSITION OF PAROLEE EMPLOYMENT AUTHORIZATION APPLICATION FEES.—All of the fees collected pursuant to this subsection shall be deposited into the general fund of the Treasury.

(5) NO FEE WAIVER.—Fees required to be paid under this subsection shall not be waived or reduced.

(c) TEMPORARY PROTECTED STATUS.—

(1) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this subsection, by any alien who files an initial application for employment authorization under section 244(a)(1)(B) (8 U.S.C. 1254a(a)(1)(B)) at the time such initial application is filed. Each initial employment authorization shall be valid for a period of 1 year, or for the duration of the alien's temporary protected status, whichever is shorter.

(2) INITIAL AMOUNT.—During fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $550; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(3) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this subsection shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(4) DISPOSITION OF EMPLOYMENT AUTHORIZATION APPLICATION FEES COLLECTED FROM ALIENS GRANTED TEMPORARY PROTECTED STATUS.—All of the fees collected pursuant to this subsection shall be deposited into the general fund of the Treasury.

(5) NO FEE WAIVER.—Fees required to be paid under this subsection shall not be waived or reduced.

SEC. 100004. IMMIGRATION PAROLE FEE.

(a) IN GENERAL.—Except as provided under subsection (b), the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this section and in addition to any other fee authorized by law, by any alien who is paroled into the United States.

(b) EXCEPTIONS.—An alien shall not be subject to the fee otherwise required under subsection (a) if the alien establishes, to the satisfaction of the Secretary of Homeland Security, on an individual, case-by-case basis, that the alien is being paroled because—

(1)(A) the alien has a medical emergency; and

(B)(i) the alien cannot obtain necessary treatment in the foreign state in which the alien is residing; or

(ii) the medical emergency is life-threatening and there is insufficient time for the alien to be admitted to the United States through the normal visa process;

(2)(A) the alien is the parent or legal guardian of an alien described in paragraph (1); and

(B) the alien described in paragraph (1) is a minor;

(3)(A) the alien is needed in the United States to donate an organ or other tissue for transplant; and

(B) there is insufficient time for the alien to be admitted to the United States through the normal visa process;

(4)(A) the alien has a close family member in the United States whose death is imminent; and

(B) the alien could not arrive in the United States in time to see such family member alive if the alien were to be admitted to the United States through the normal visa process;

(5)(A) the alien is seeking to attend the funeral of a close family member; and

(B) the alien could not arrive in the United States in time to attend such funeral if the alien were to be admitted to the United States through the normal visa process;

(6) the alien is an adopted child—

(A) who has an urgent medical condition;

(B) who is in the legal custody of the petitioner for a final adoption-related visa; and

(C) whose medical treatment is required before the expected award of a final adoption-related visa;

(7) the alien—

(A) is a lawful applicant for adjustment of status under section 245 (8 U.S.C. 1255); and

(B) is returning to the United States after temporary travel abroad;

(8) the alien—

(A) has been returned to a contiguous country pursuant to section 235(b)(2)(C) (8 U.S.C. 1225(b)(2)(C)); and

(B) is being paroled into the United States to allow the alien to attend the alien's immigration hearing;

(9) the alien has been granted the status of Cuban and Haitian entrant (as defined in section 501(e) of the Refugee Education Assistance Act of 1980 (Public Law 96-422; 8 U.S.C. 1522 note); or

(10) the Secretary of Homeland Security determines that a significant public benefit has resulted or will result from the parole of an alien—

(A) who has assisted or will assist the United States Government in a law enforcement matter;

(B) whose presence is required by the United States Government in furtherance of such law enforcement matter; and

(C)(i) who is inadmissible or does not satisfy the eligibility requirements for admission as a nonimmigrant; or

(ii) for which there is insufficient time for the alien to be admitted to the United States through the normal visa process.

(c) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(1) $1,000; or

(2) such amount as the Secretary of Homeland Security may establish, by rule.

(d) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(1) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(2) the product resulting from the multiplication of the amount referred to in paragraph (1) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(e) DISPOSITION OF FEES COLLECTED FROM ALIENS GRANTED PAROLE.—All of the fees collected pursuant to this section shall be deposited into the general fund of the Treasury.

(f) NO FEE WAIVER.—Except as provided in subsection (b), fees required to be paid under this section shall not be waived or reduced.

SEC. 100005. SPECIAL IMMIGRANT JUVENILE FEE.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this section, by any alien, parent, or legal guardian of an alien applying for special immigrant juvenile status under section 101(a)(27)(J) (8 U.S.C. 1101(a)(27)(J)).

(b) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(1) $250; or

(2) such amount as the Secretary of Homeland Security may establish, by rule.

(c) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(1) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(2) the product resulting from the multiplication of the amount referred to in paragraph (1) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(d) DISPOSITION OF SPECIAL IMMIGRANT JUVENILE FEES.—All of the fees collected pursuant to this section shall be deposited into the general fund of the Treasury.

SEC. 100006. TEMPORARY PROTECTED STATUS FEE.

Section 244(c)(1)(B) of the Immigration and Nationality Act (8 U.S.C. 1254a(c)(1)(B)) is amended—

(1) by striking "The Attorney General" and inserting the following:

"(i) IN GENERAL.—The Attorney General";

(2) in clause (i), as redesignated, by striking "$50" and inserting "$500, subject to the adjustments required under clause (ii)"; and

(3) by adding at the end the following:

"(ii) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the maximum amount of the fee authorized under clause (i) shall be equal to the sum of—

"(I) the maximum amount of the fee authorized under this subparagraph for the most recently concluded fiscal year; and

"(II) the product resulting from the multiplication of the amount referred to in subclause (I) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

"(iii) DISPOSITION OF TEMPORARY PROTECTED STATUS FEES.—All of the fees collected pursuant to this subparagraph shall be deposited into the general fund of the Treasury.

"(iv) NO FEE WAIVER.—Fees required to be paid under this subparagraph shall not be waived or reduced.".

SEC. 100007. VISA INTEGRITY FEE.

(a) VISA INTEGRITY FEE.—

(1) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in this subsection, by any alien issued a nonimmigrant visa at the time of such issuance.

(2) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(A) $250; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(3) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded down to the nearest dollar.

(4) DISPOSITION OF VISA INTEGRITY FEES.—All of the fees collected pursuant to this section that are not reimbursed pursuant to subsection (b) shall be deposited into the general fund of the Treasury.

(5) NO FEE WAIVER.—Fees required to be paid under this subsection shall not be waived or reduced.

(b) FEE REIMBURSEMENT.—The Secretary of Homeland Security may provide a reimbursement to an alien of the fee required under subsection (a) for the issuance of a nonimmigrant visa after the expiration of such nonimmigrant visa's period of validity if such alien demonstrates that he or she—

(1) after admission to the United States pursuant to such nonimmigrant visa, complied with all conditions of such nonimmigrant visa, including the condition that an alien shall not accept unauthorized employment; and

(2)(A) has not sought to extend his or her period of admission during such period of validity and departed the United States not later than 5 days after the last day of such period; or

(B) during such period of validity, was granted an extension of such nonimmigrant status or an adjustment to the status of a lawful permanent resident.

SEC. 100008. FORM I–94 FEE.

(a) FEE AUTHORIZED.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in subsection (b), by any alien who submits an application for a Form I–94 Arrival/Departure Record.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(A) $24; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded down to the nearest dollar.

(c) DISPOSITION OF FORM I–94 FEES.—During each fiscal year—

(1) 20 percent of the fees collected pursuant to this section—

(A) shall be deposited into the Land Border Inspection Fee Account in accordance with section 286(q)(2) (8 U.S.C. 1356(q)(2)); and

(B) shall be made available to U.S. Customs and Border Protection to retain and spend without further appropriation for the purpose of processing Form I–94; and

(2) any amounts not deposited into the Land Border Inspection Fee Account pursuant to paragraph (1)(A) shall be deposited in the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100009. ANNUAL ASYLUM FEE.

(a) FEE AUTHORIZED.—In addition to any other fee authorized by law, for each calendar year that an alien's application for asylum remains pending, the Secretary of Homeland Security or the Attorney General, as applicable, shall require the payment of a fee, equal to the amount specified in subsection (b), by such alien.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(A) $100; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded down to the nearest dollar.

(c) DISPOSITION OF ANNUAL ASYLUM FEES.—All of the fees collected pursuant to this section shall be deposited into the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100010. FEE RELATING TO RENEWAL AND EXTENSION OF EMPLOYMENT AUTHORIZATION FOR PAROLEES.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in subsection (b), for any parolee who seeks a renewal or extension of employment authorization based on a grant of parole. The employment authorization for each alien paroled into the United States, or any renewal or extension of such parole, shall be valid for a period of 1 year or for the duration of the alien's parole, whichever is shorter.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $275; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(c) DISPOSITION OF FEES RELATING TO RENEWAL AND EXTENSION OF EMPLOYMENT AUTHORIZATION FOR PAROLEES.—During each fiscal year—

(1) 25 percent of the fees collected pursuant to this section—

(A) shall be credited to U.S. Citizenship and Immigration Services;

(B) shall be deposited into the Immigration Examinations Fee Account established under section 286(m) (8 U.S.C. 1356(m)); and

(C) may be retained and expended by U.S. Citizenship and Immigration Services without further appropriation; and

(2) any amounts collected pursuant to this section that are not credited to U.S. Citizenship and Immigration Services pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100011. FEE RELATING TO RENEWAL OR EXTENSION OF EMPLOYMENT AUTHORIZATION FOR ASYLUM APPLICANTS.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee of not less than $275 by any alien who has applied for asylum for each renewal or extension of employment authorization based on such application.

(b) TERMINATION.—Each initial employment authorization, or renewal or extension of such authorization, shall terminate—

(1) immediately following the denial of an asylum application by an asylum officer, unless the case is referred to an immigration judge;

(2) on the date that is 30 days after the date on which an immigration judge denies an asylum application, unless the alien makes a timely appeal to the Board of Immigration Appeals; or

(3) immediately following the denial by the Board of Immigration Appeals of an appeal of a denial of an asylum application.

(c) DISPOSITION OF FEES RELATING TO RENEWAL AND EXTENSION OF EMPLOYMENT AUTHORIZATION FOR ASYLUM APPLICANTS.—During each fiscal year—

(1) 25 percent of the fees collected pursuant to this section—

(A) shall be credited to U.S. Citizenship and Immigration Services;

(B) shall be deposited into the Immigration Examinations Fee Account established under section 286(m) (8 U.S.C. 1356(m)); and

(C) may be retained and expended by U.S. Citizenship and Immigration Services without further appropriation; and

(2) any amounts collected pursuant to this section that are not credited to U.S. Citizenship and Immigration Services pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100012. FEE RELATING TO RENEWAL AND EXTENSION OF EMPLOYMENT AUTHORIZATION FOR ALIENS GRANTED TEMPORARY PROTECTED STATUS.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in subsection (b), by any alien at the time such alien seeks a renewal or extension of employment authorization based on a grant of temporary protected status. Any employment authorization for an alien granted temporary protected status, or any renewal or extension of such employment authorization, shall be valid for a period of 1 year or for the duration of the designation of temporary protected status, whichever is shorter.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $275; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(c) DISPOSITION OF FEES RELATING TO RENEWAL AND EXTENSION OF EMPLOYMENT AUTHORIZATION FOR TEMPORARY PROTECTED STATUS APPLICANTS.—During each fiscal year—

(1) 25 percent of the fees collected pursuant to this section—

(A) shall be credited to U.S. Citizenship and Immigration Services;

(B) shall be deposited into the Immigration Examinations Fee Account established under section 286(m) (8 U.S.C. 1356(m)); and

(C) may be retained and expended by U.S. Citizenship and Immigration Services without further appropriation; and

(2) any amounts collected pursuant to this section that are not credited to U.S. Citizenship and Immigration Services pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100013. FEES RELATING TO APPLICATIONS FOR ADJUSTMENT OF STATUS.

(a) FEE FOR FILING AN APPLICATION TO ADJUST STATUS TO THAT OF A LAWFUL PERMANENT RESIDENT.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien who files an application with an immigration court to adjust the alien's status to that of a lawful permanent resident, or whose application to adjust his or her status to that of a lawful permanent resident is adjudicated in immigration court. Such fee shall be paid at the time such application is filed or before such application is adjudicated by the immigration court.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $1,500; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF ADJUSTMENT OF STATUS APPLICATION FEES.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(b) FEE FOR FILING APPLICATION FOR WAIVER OF GROUNDS OF INADMISSIBILITY.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files an application with an immigration court for a waiver of a ground of inadmissibility, or before such application is adjudicated by the immigration court.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $1,050; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF WAIVER OF GROUND OF ADMISSIBILITY APPLICATION FEES.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(c) FEE FOR FILING AN APPLICATION FOR TEMPORARY PROTECTED STATUS.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files an application with an immigration court for temporary protected status, or before such application is adjudicated by the immigration court.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $500; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF TEMPORARY PROTECTED STATUS APPLICATION FEES.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(d) FEE FOR FILING AN APPEAL OF A DECISION OF AN IMMIGRATION JUDGE.—

(1) IN GENERAL.—Except as provided in paragraph (3), the Attorney General shall require, in addition to any other fees authorized by law, the payment of a fee, equal to the amount

specified in paragraph (2), by any alien at the time such alien files an appeal from a decision of an immigration judge.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $900; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) EXCEPTION.—The fee required under paragraph (1) shall not apply to the appeal of a bond decision.

(4) DISPOSITION OF FEES FOR APPEALING IMMIGRATION JUDGE DECISIONS.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(e) FEE FOR FILING AN APPEAL FROM A DECISION OF AN OFFICER OF THE DEPARTMENT OF HOMELAND SECURITY.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files an appeal of a decision of an officer of the Department of Homeland Security.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $900; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF FEES FOR APPEALING DEPARTMENT OF HOMELAND SECURITY OFFICER DECISIONS.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(f) FEE FOR FILING AN APPEAL FROM A DECISION OF AN ADJUDICATING OFFICIAL IN A PRACTITIONER DISCIPLINARY CASE.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any practitioner at the time such practitioner files an appeal from a decision of an adjudicating official in a practitioner disciplinary case.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $1,325; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF FEES FOR APPEALING DEPARTMENT OF HOMELAND SECURITY OFFICER DECISIONS.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(g) FEE FOR FILING A MOTION TO REOPEN OR A MOTION TO RECONSIDER.—

(1) IN GENERAL.—Except as provided in paragraph (3), in addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files a motion to reopen or motion to reconsider a decision of an immigration judge or the Board of Immigration Appeals.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $900; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) EXCEPTIONS.—The fee required under paragraph (1) shall not apply to—

(A) a motion to reopen a removal order entered in absentia if such motion is filed in accordance with section 240(b)(5)(C)(ii) (8 U.S.C. 1229a(b)(5)(C)(ii)); or

(B) a motion to reopen a deportation order entered in absentia if such motion is filed in accordance with section 242B(c)(3)(B) prior to April 1, 1997.

(4) DISPOSITION OF FEES FOR FILING CERTAIN MOTIONS.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(h) FEE FOR FILING APPLICATION FOR SUSPENSION OF DEPORTATION.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files an application with an immigration court for suspension of deportation.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $600; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF FEES FOR FILING APPLICATION FOR SUSPENSION OF DEPORTATION.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(i) FEE FOR FILING APPLICATION FOR CANCELLATION OF REMOVAL FOR CERTAIN PERMANENT RESIDENTS.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien at the time such alien files an application with an immigration court an application for cancellation of removal for an alien who is a lawful permanent resident.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $600; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF FEES FOR FILING APPLICATION FOR CANCELLATION OF REMOVAL.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(j) FEE FOR FILING AN APPLICATION FOR CANCELLATION OF REMOVAL AND ADJUSTMENT OF STATUS FOR CERTAIN NONPERMANENT RESIDENTS.—

(1) IN GENERAL.—In addition to any other fees authorized by law, the Attorney General shall require the payment of a fee, equal to the amount specified in paragraph (2), by any alien who is not a lawful permanent resident at the time such alien files an application with an immigration court for cancellation of removal and adjustment of status for any alien.

(2) AMOUNT SPECIFIED.—

(A) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this paragraph shall be the greater of—

(i) $1,500; or

(ii) such amount as the Attorney General may establish, by rule.

(B) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this paragraph shall be equal to the sum of—

(i) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(ii) the product resulting from the multiplication of the amount referred to in clause (i) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(3) DISPOSITION OF FEES FOR FILING APPLICATION FOR CANCELLATION OF REMOVAL.—During each fiscal year—

(A) not more than 25 percent of the fees collected pursuant to this subsection—

(i) shall be derived by transfer from the Immigration Examinations Fee Account under section 286(n) (8 U.S.C. 1356(n)); and

(ii) shall be credited to the Executive Office for Immigration Review to retain and spend without further appropriation; and

(B) any amounts not derived by transfer and credited pursuant to subparagraph (A) shall be deposited into the general fund of the Treasury.

(k) LIMITATION ON USE OF FUNDS.—No fees collected pursuant to this section may be expended by the Executive Office for Immigration Review for the Legal Orientation Program, or for any successor program.

SEC. 100014. ELECTRONIC SYSTEM FOR TRAVEL AUTHORIZATION FEE.

Section 217(h)(3)(B) (8 U.S.C. 1187(h)(3)(B)) is amended—

(1) in clause (i)—

(A) in subclause (I), by striking "and" at the end;

(B) in subclause (II)—

(i) by inserting "of not less than $10" after "an amount"; and

(ii) by striking the period at the end and inserting "; and"; and

(C) by adding at the end the following:

"(III) not less than $13 per travel authorization.";

(2) in clause (iii), by striking "October 31, 2028" and inserting "October 31, 2034"; and

(3) by adding at the end the following:

"(iv) SUBSEQUENT ADJUSTMENT.—During fiscal year 2026 and each subsequent fiscal year, the amount specified in clause (i)(II) for a fiscal year shall be equal to the sum of—

"(I) the amount of the fee required under this subparagraph during the most recently concluded fiscal year; and

"(II) the product of the amount referred to in subclause (I) multiplied by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year.".

SEC. 100015. ELECTRONIC VISA UPDATE SYSTEM FEE.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, in the amount specified in subsection (b), by any alien subject to the Electronic Visa Update System at the time of such alien's enrollment in such system.

(b) AMOUNT SPECIFIED.—

(1) IN GENERAL.—For fiscal year 2025, the amount specified in this subsection shall be the greater of—

(A) $30; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026 and each subsequent fiscal year, the amount specified in this subsection shall be equal to the sum of—

(A) the amount of the fee required under this subsection during the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $0.25.

(c) DISPOSITION OF ELECTRONIC VISA UPDATE SYSTEM FEES.—

(1) IN GENERAL.—Section 286 (8 U.S.C. 1356) is amended by adding at the end the following:

"(w) CBP ELECTRONIC VISA UPDATE SYSTEM ACCOUNT.—

"(1) ESTABLISHMENT.—There is established in the general fund of the Treasury a separate account, which shall be known as the 'CBP Electronic Visa Update System Account' (referred to in this subsection as the 'Account').

"(2) DEPOSITS.—There shall be deposited into the Account an amount equal to the difference between—

"(A) all of the fees received pursuant to section 100015 of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress); and

"(B) an amount equal to $5 multiplied by the number of payments collected pursuant to such section.

"(3) APPROPRIATION.—Amounts deposited in the Account—

"(A) are hereby appropriated to make payments and offset program costs in accordance with section 100015 of the Act entitled 'An Act to provide for reconciliation pursuant to title II of H. Con. Res. 14' (119th Congress), without further appropriation; and

"(B) shall remain available until expended for any U.S. Customs and Border Protection costs associated with administering the CBP Electronic Visa Update System.".

(2) REMAINING FEES.—Of the fees collected pursuant to this section, an amount equal to $5 multiplied by the number of payments collected pursuant to this section shall be deposited to the general fund of the Treasury.

(d) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100016. FEE FOR ALIENS ORDERED REMOVED IN ABSENTIA.

(a) IN GENERAL.—As partial reimbursement for the cost of arresting an alien described in this section, the Secretary of Homeland Security, except as provided in subsection (c), shall require the payment of a fee, equal to the amount specified in subsection (b) on any alien who—

(1) is ordered removed in absentia pursuant to section 240(b)(5) (8 U.S.C. 1229a(b)(5)); and

(2) is subsequently arrested by U.S. Immigration and Customs Enforcement.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(A) $5,000; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(c) EXCEPTION.—The fee described in this section shall not apply to any alien who was ordered removed in absentia if such order was rescinded pursuant to section 240(b)(5)(C) (8 U.S.C. 1229a(b)(5)(C)).

(d) DISPOSITION OF REMOVAL IN ABSENTIA FEES.—During each fiscal year—

(1) 50 percent of the fees collected pursuant to this section—

(A) shall be credited to U.S. Immigration and Customs Enforcement;

(B) shall be deposited into the Detention and Removal Office Fee Account; and

(C) may be retained and expended by U.S. Immigration and Customs Enforcement without further appropriation; and

(2) any amounts collected pursuant to this section that are not credited to U.S. Immigration and Customs Enforcement pursuant to paragraph (1) shall be deposited into the general fund of the Treasury.

(e) NO FEE WAIVER.—Fees required to be paid under this section shall not be waived or reduced.

SEC. 100017. INADMISSIBLE ALIEN APPREHENSION FEE.

(a) IN GENERAL.—In addition to any other fee authorized by law, the Secretary of Homeland Security shall require the payment of a fee, equal to the amount specified in subsection (b), by any inadmissible alien at the time such alien is apprehended between ports of entry.

(b) AMOUNT SPECIFIED.—

(1) INITIAL AMOUNT.—For fiscal year 2025, the amount specified in this section shall be the greater of—

(A) $5,000; or

(B) such amount as the Secretary of Homeland Security may establish, by rule.

(2) ANNUAL ADJUSTMENTS FOR INFLATION.—During fiscal year 2026, and during each subsequent fiscal year, the amount specified in this section shall be equal to the sum of—

(A) the amount of the fee required under this subsection for the most recently concluded fiscal year; and

(B) the product resulting from the multiplication of the amount referred to in subparagraph (A) by the percentage (if any) by which the Consumer Price Index for All Urban Consumers for the month of July preceding the date on which such adjustment takes effect exceeds the Consumer Price Index for All Urban Consumers for the same month of the preceding calendar year, rounded to the next lowest multiple of $10.

(c) DISPOSITION OF INADMISSIBLE ALIEN APPREHENSION FEES.—During each fiscal year—

(1) 50 percent of the fees collected pursuant to this section—

(A) shall be credited to U.S. Immigration and Customs Enforcement;

(B) shall be deposited into the Detention and Removal Office Fee Account; and

(C) may be retained and expended by U.S. Immigration and Customs Enforcement without further appropriation; and

(2) any amounts collected pursuant to this section that are not credited to U.S. Immigration and Customs Enforcement pursuant to paragraph (1) shall be deposited into the general fund of the Treasury.

(d) DISPOSITION OF INADMISSIBLE ALIEN APPREHENSION FEES.—All of the fees collected pursuant to this section shall be deposited into the general fund of the Treasury.

SEC. 100018. AMENDMENT TO AUTHORITY TO APPLY FOR ASYLUM.

Section 208(d)(3) (8 U.S.C. 1158(d)(3)) is amended—

(1) in the first sentence, by striking "may" and inserting "shall";

(2) by striking "Such fees shall not exceed" and all that follows and inserting the following: "Nothing in this paragraph may be construed to limit the authority of the Attorney General to set additional adjudication and naturalization fees in accordance with section 286(m).".

PART II—IMMIGRATION AND LAW ENFORCEMENT FUNDING

SEC. 100051. APPROPRIATION FOR THE DEPARTMENT OF HOMELAND SECURITY.

In addition to amounts otherwise available, there is appropriated to the Secretary of Homeland Security for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $2,055,000,000, to remain available through September 30, 2029, for the following purposes:

(1) IMMIGRATION AND ENFORCEMENT ACTIVITIES.—Hiring and training of additional U.S. Customs and Border Protection agents, and the necessary support staff, to carry out immigration enforcement activities.

(2) DEPARTURES AND REMOVALS.—Funding for transportation costs and related costs associated with the departure or removal of aliens.

(3) PERSONNEL ASSIGNMENTS.—Funding for the assignment of Department of Homeland Security employees and State officers to carry out immigration enforcement activities pursuant to sections 103(a) and 287(g) of the Immigration and Nationality Act (8 U.S.C. 1103(a) and 1357(g)).

(4) BACKGROUND CHECKS.—Hiring additional staff and investing the necessary resources to enhance screening and vetting of all aliens seeking entry into United States, consistent with section 212 of such Act (8 U.S.C. 1182), or intending to remain in the United States, consistent with section 237 of such Act (8 U.S.C. 1227).

(5) PROTECTING ALIEN CHILDREN FROM EXPLOITATION.—In instances of aliens and alien children entering the United States without a valid visa, funding is provided for the purposes of—

(A) collecting fingerprints, in accordance with section 262 of the Immigration and Nationality Act (8 U.S.C. 1302) and subsections (a)(3) and (b) of section 235 of such Act (8 U.S.C. 1225); and

(B) collecting DNA, in accordance with sections 235(d) and 287(b) of the Immigration and Nationality Act (8 U.S.C. 1225(d) and 1357(b)).

(6) TRANSPORTING AND RETURN OF ALIENS FROM CONTIGUOUS TERRITORY.—Transporting and facilitating the return, pursuant to section 235(b)(2)(C) of the Immigration and Nationality Act (8 U.S.C. 1225(b)(2)(C)), of aliens arriving from contiguous territory.

(7) STATE AND LOCAL PARTICIPATION.—Funding for State and local participation in homeland security efforts for purposes of—

(A) ending the presence of criminal gangs and criminal organizations throughout the United States;

(B) addressing crime and public safety threats;

(C) combating human smuggling and trafficking networks throughout the United States;

(D) supporting immigration enforcement activities; and

(E) providing reimbursement for State and local participation in such efforts.

(8) REMOVAL OF SPECIFIED UNACCOMPANIED ALIEN CHILDREN.—

(A) IN GENERAL.—Funding removal operations for specified unaccompanied alien children.

(B) USE OF FUNDS.—Amounts made available under this paragraph shall only be used for permitting a specified unaccompanied alien child to withdraw the application for admission of the child pursuant to section 235(a)(4) of the Immigration and Nationality Act (8 U.S.C. 1225(a)(4)).

(C) DEFINITIONS.—In this paragraph:

(i) SPECIFIED UNACCOMPANIED ALIEN CHILD.—The term "specified unaccompanied alien child" means an unaccompanied alien child (as defined in section 462(g) of the Homeland Security Act of 2002 (6 U.S.C. 279(g))) who the Secretary of Homeland Security determines on a case-by-case basis—

(I) has been found by an immigration officer at a land border or port of entry of the United States and is inadmissible under the Immigration and Nationality Act (8 U.S.C. 1101 et seq.);

(II) has not been a victim of severe forms of trafficking in persons, and there is no credible evidence that such child is at risk of being trafficked upon return of the child to the child's country of nationality or country of last habitual residence; and

(III) does not have a fear of returning to the child's country of nationality or country of last habitual residence owing to a credible fear of persecution.

(ii) SEVERE FORMS OF TRAFFICKING IN PERSONS.—The term "severe forms of trafficking in persons" has the meaning given such term in section 103 of the Trafficking Victims Protection Act of 2000 (22 U.S.C. 7102).

(9) EXPEDITED REMOVAL OF CRIMINAL ALIENS.—Funding for the expedited removal of criminal aliens, in accordance with the provisions of section 235(b)(1) of the Immigration and Nationality Act (8 U.S.C. 1225(b)(1)).

(10) REMOVAL OF CERTAIN CRIMINAL ALIENS WITHOUT FURTHER HEARINGS.—Funding for the removal of certain criminal aliens without further hearings, in accordance with the provisions of section 235(c) of the Immigration and Nationality Act (8 U.S.C. 1225(c)).

(11) CRIMINAL AND GANG CHECKS FOR UNACCOMPANIED ALIEN CHILDREN.—Funding for criminal and gang checks of unaccompanied alien children (as defined in section 462(g) of the Homeland Security Act of 2002 (6 U.S.C. 279(g))) who are 12 years of age and older, including the examination of such unaccompanied alien children for gang-related tattoos and other gang-related markings.

(12) INFORMATION TECHNOLOGY.—Information technology investments to support immigration purposes, including improvements to fee and revenue collections.

SEC. 100052. APPROPRIATION FOR U.S. IMMIGRATION AND CUSTOMS ENFORCEMENT.

In addition to amounts otherwise available, there is appropriated to the Secretary of Homeland Security for U.S. Immigration and Customs Enforcement for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $29,850,000,000, to remain available through September 30, 2029, for the following purposes:

(1) HIRING AND TRAINING.—Hiring and training additional U.S. Immigration and Customs Enforcement personnel, including officers, agents, investigators, and support staff, to carry out immigration enforcement activities and prioritizing and streamlining the hiring of retired U.S. Immigration and Customs Enforcement personnel.

(2) PERFORMANCE, RETENTION, AND SIGNING BONUSES.—

(A) IN GENERAL.—Providing performance, retention, and signing bonuses for qualified U.S. Immigration and Customs Enforcement personnel in accordance with this subsection.

(B) PERFORMANCE BONUSES.—The Director of U.S. Immigration and Customs Enforcement, at the Director's discretion, may provide performance bonuses to any U.S. Immigration and Customs Enforcement agent, officer, or attorney who demonstrates exemplary service.

(C) RETENTION BONUSES.—The Director of U.S. Immigration and Customs Enforcement may provide retention bonuses to any U.S. Immigration and Customs Enforcement agent, officer, or attorney who commits to 2 years of additional service with U.S. Immigration and Customs Enforcement to carry out immigration enforcement activities.

(D) SIGNING BONUSES.—The Director of U.S. Immigration and Customs Enforcement may provide a signing bonus to any U.S. Immigration and Customs Enforcement agent, officer, or attorney who—

(i) is hired on or after the date of the enactment of this Act; and

(ii) who commits to 5 years of service with U.S. Immigration and Customs Enforcement to carry out immigration enforcement activities.

(E) SERVICE AGREEMENT.—In providing a retention or signing bonus under this paragraph, the Director of U.S. Immigration and Customs Enforcement shall provide each qualifying individual with a written service agreement that includes—

(i) the commencement and termination dates of the required service period (or provisions for the determination of such dates);

(ii) the amount of the bonus; and

(iii) any other term or condition under which the bonus is payable, subject to the requirements of this paragraph, including—

(I) the conditions under which the agreement may be terminated before the agreed-upon service period has been completed; and

(II) the effect of a termination described in subclause (I).

(3) RECRUITMENT, HIRING, AND ONBOARDING.—Facilitating the recruitment, hiring, and onboarding of additional U.S. Immigration and Customs Enforcement personnel to carry out immigration enforcement activities, including by—

(A) investing in information technology, recruitment, and marketing; and

(B) hiring staff necessary to carry out information technology, recruitment, and marketing activities.

(4) TRANSPORTATION.—Funding for transportation costs and related costs associated with alien departure or removal operations.

(5) INFORMATION TECHNOLOGY.—Funding for information technology investments to support enforcement and removal operations, including improvements to fee collections.

(6) FACILITY UPGRADES.—Funding for facility upgrades to support enforcement and removal operations.

(7) FLEET MODERNIZATION.—Funding for fleet modernization to support enforcement and removal operations.

(8) FAMILY UNITY.—Promoting family unity by—

(A) maintaining the care and custody, during the period in which a charge described in clause (i) is pending, in accordance with applicable laws, of an alien who—

(i) is charged only with a misdemeanor offense under section 275(a) of the Immigration and Nationality Act (8 U.S.C. 1325(a)); and

(ii) entered the United States with the alien's child who has not attained 18 years of age; and

(B) detaining such an alien with the alien's child.

(9) 287(g) AGREEMENTS.—Expanding, facilitating, and implementing agreements under section 287(g) of the Immigration and Nationality Act (8 U.S.C. 1357(g)).

(10) VICTIMS OF IMMIGRATION CRIME ENGAGEMENT OFFICE.—Hiring and training additional staff to carry out the mission of the Victims of Immigration Crime Engagement Office and for providing nonfinancial assistance to the victims of crimes perpetrated by aliens who are present in the United States without authorization.

(11) OFFICE OF THE PRINCIPAL LEGAL ADVISOR.—Hiring additional attorneys and the necessary support staff within the Office of the Principal Legal Advisor to represent the Department of Homeland Security in immigration enforcement and removal proceedings.

SEC. 100053. APPROPRIATION FOR FEDERAL LAW ENFORCEMENT TRAINING CENTERS.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Secretary of Homeland Security for the Federal Law Enforcement Training Centers for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $750,000,000, to remain available until September 30, 2029, for the purposes described in subsections (b) and (c).

(b) TRAINING.—Not less than $285,000,000 of the amounts available under subsection (a) shall be for supporting the training of newly hired Federal law enforcement personnel employed by the Department of Homeland Security and State and local law enforcement agencies operating in support of the Department of Homeland Security.

(c) FACILITIES.—Not more than $465,000,000 of the amounts available under subsection (a) shall be for procurement, construction and maintenance of, improvements to, training equipment for, and related expenses, of facilities of the Federal Law Enforcement Training Centers.

SEC. 100054. APPROPRIATION FOR THE DEPARTMENT OF JUSTICE.

In addition to amounts otherwise available, there is appropriated to the Attorney General for the Department of Justice for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $3,330,000,000, to remain available through September 30, 2029, for the following purposes:

(1) EXECUTIVE OFFICE FOR IMMIGRATION REVIEW.—

(A) IN GENERAL.—Hiring immigration judges and necessary support staff for the Executive Office for Immigration Review to address the backlog of petitions, cases, and removals.

(B) STAFFING LEVEL.—Effective November 1, 2028, the Executive Office for Immigration Review shall be comprised of not more than 800 immigration judges, along with the necessary support staff.

(2) COMBATING DRUG TRAFFICKING.—Funding efforts to combat drug trafficking (including trafficking of fentanyl and its precursor chemicals) and illegal drug use.

(3) PROSECUTION OF IMMIGRATION MATTERS.—Funding efforts to investigate and prosecute immigration matters, gang-related crimes involving aliens, child trafficking and smuggling involving aliens within the United States, unlawful voting by aliens, violations of the Alien Registration Act, 1940 (54 Stat., chapter 439), and violations of or fraud relating to title IV of the Personal Responsibility and Work Opportunity Act of 1996 (Public Law 104–193; 110 Stat. 2277), including hiring additional Department of Justice personnel to investigate and prosecute such matters.

(4) NONPARTY OR OTHER INJUNCTIVE RELIEF.—Hiring additional attorneys and necessary support staff for the purpose of continuing implementation of assignments by the Attorney General pursuant to sections 516, 517, and 518 of title 28, United States Code, to conduct litigation and attend to the interests of the United States in suits pending in a court of the United States or in a court of a State in suits seeking nonparty or other injunctive relief against the Federal Government.

(5) EDWARD BYRNE MEMORIAL JUSTICE ASSISTANCE GRANT PROGRAM AND OFFICE OF COMMUNITY ORIENTED POLICING.—

(A) IN GENERAL.—Increasing funding for the Edward Byrne Memorial Justice Assistance Grant Program and the Office of Community Oriented Policing for initiatives associated with—

(i) investigating and prosecuting violent crime;

(ii) criminal enforcement initiatives; and

(iii) immigration enforcement and removal efforts.

(B) LIMITATIONS.—No funds made available under this subsection shall be made available to community violence intervention and prevention initiative programs.

(C) ELIGIBILITY.—To be eligible to receive funds made available under this subsection, a State or local government shall be in full compliance, as determined by the Attorney General, with section 642 of the Illegal Immigration Reform and Immigrant Responsibility Act of 1996 (8 U.S.C. 1373).

(6) FISCALLY RESPONSIBLE LAWSUIT SETTLEMENTS.—Hiring additional attorneys and necessary support staff for the purpose of maximizing lawsuit settlements that require the payment of fines and penalties to the Treasury of the United States in lieu of providing for the payment to any person or entity other than the United States, other than a payment that provides restitution or otherwise directly remedies actual harm directly and proximately caused by the party making the payment, or constitutes payment for services rendered in connection with the case.

(7) COMPENSATION FOR INCARCERATION OF CRIMINAL ALIENS.—

(A) IN GENERAL.—Providing compensation to a State or political subdivision of a State for the incarceration of criminal aliens.

(B) USE OF FUNDS.—The amounts made available under subparagraph (A) shall only be used to compensate a State or political subdivision of a State, as appropriate, with respect to the incarceration of an alien who—

(i) has been convicted of a felony or 2 or more misdemeanors; and

(ii)(I) entered the United States without inspection or at any time or place other than as designated by the Secretary of Homeland Security;

(II) was the subject of removal proceedings at the time the alien was taken into custody by the State or a political subdivision of the State; or

(III) was admitted as a nonimmigrant and, at the time the alien was taken into custody by the State or a political subdivision of the State, has failed to maintain the nonimmigrant status in which the alien was admitted, or to which it was changed, or to comply with the conditions of any such status.

(C) LIMITATION.—Amounts made available under this subsection shall be distributed to more than 1 State. The amounts made available under subparagraph (A) may not be used to compensate any State or political subdivision of a State if the State or political subdivision of the State prohibits or in any way restricts a Federal, State, or local government entity, official, or other personnel from doing any of the following:

(i) Complying with the immigration laws (as defined in section 101(a)(17) of the Immigration and Nationality Act (8 U.S.C. 1101(a)(17))).

(ii) Assisting or cooperating with Federal law enforcement entities, officials, or other personnel regarding the enforcement of the immigration laws.

(iii) Undertaking any of the following law enforcement activities as such activities relate to information regarding the citizenship or immigration status, lawful or unlawful, the inadmissibility or deportability, and the custody status, of any individual:

(I) Making inquiries to any individual to obtain such information regarding such individual or any other individuals.

(II) Notifying the Federal Government regarding the presence of individuals who are encountered by law enforcement officials or other personnel of a State or political subdivision of a State.

(III) Complying with requests for such information from Federal law enforcement entities, officials, or other personnel.

SEC. 100055. BRIDGING IMMIGRATION-RELATED DEFICITS EXPERIENCED NATIONWIDE REIMBURSEMENT FUND.

(a) ESTABLISHMENT.—There is established within the Department of Justice a fund, to be known as the "Bridging Immigration-related Deficits Experienced Nationwide (BIDEN) Reimbursement Fund" (referred to in this section as the "Fund").

(b) USE OF FUNDS.—The Attorney General shall use amounts appropriated or otherwise made available for the Fund for grants to eligible States, State agencies, and units of local government, pursuant to their existing statutory authorities, for any of the following purposes:

(1) Locating and apprehending aliens who have committed a crime under Federal, State, or local law, in addition to being unlawfully present in the United States.

(2) Collection and analysis of law enforcement investigative information within the United States to counter gang or other criminal activity.

(3) Investigating and prosecuting—

(A) crimes committed by aliens within the United States; and

(B) drug and human trafficking crimes committed within the United States.

(4) Court operations related to the prosecution of—

(A) crimes committed by aliens; and

(B) drug and human trafficking crimes.

(5) Temporary criminal detention of aliens.

(6) Transporting aliens described in paragraph (1) within the United States to locations related to the apprehension, detention, and prosecution of such aliens.

(7) Vehicle maintenance, logistics, transportation, and other support provided to law enforcement agencies by a State agency to enhance the ability to locate and apprehend aliens who have committed crimes under Federal, State, or local law, in addition to being unlawfully present in the United States.

(c) APPROPRIATION.—In addition to amounts otherwise available for the purposes described in subsection (b), there is appropriated to the Attorney General for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, not to exceed $3,500,000,000, to remain available until September 30, 2028, for the Fund for qualified and documented expenses that achieve any such purpose.

(d) GRANT ELIGIBILITY OF COMPLETED, ONGOING, OR NEW ACTIVITIES.—The Attorney General may provide grants under this section to State agencies and units of local government for expenditures made by State agencies or units of local government for completed, ongoing, or new activities determined to be eligible for such grant funding that occurred on or after January 20, 2021. Amounts made available under this section shall be distributed to more than 1 State.

SEC. 100056. APPROPRIATION FOR THE BUREAU OF PRISONS.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Director of the Bureau of Prisons for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $5,000,000,000, to remain available through September 30, 2029, for the purposes described in subsections (b) and (c).

(b) SALARIES AND BENEFITS.—Not less than $3,000,000,000 of the amounts made available under subsection (a) shall be for hiring and training of new employees, including correctional officers, medical professionals, and facilities and maintenance employees, the necessary support staff, and for additional funding for salaries and benefits for the current workforce of the Bureau of Prisons.

(c) FACILITIES.—Not more than $2,000,000,000 of the amounts made available under subsection (a) shall be for addressing maintenance and repairs to facilities maintained or operated by the Bureau of Prisons.

SEC. 100057. APPROPRIATION FOR THE UNITED STATES SECRET SERVICE.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Director of the United States Secret Service (referred to in this section as the "Director") for fiscal year 2025, out of any money in the Treasury not otherwise appropriated, $1,170,000,000, to remain available through September 30, 2029, for the purposes described in subsection (b).

(b) USE OF FUNDS.—Amounts made available under subsection (a) may only be used for—

(1) additional United States Secret Service resources, including personnel, training facilities, programming, and technology; and

(2) performance, retention, and signing bonuses for qualified United States Secret Service personnel in accordance with subsection (c).

(c) PERFORMANCE, RETENTION, AND SIGNING BONUSES.—

(1) PERFORMANCE BONUSES.—The Director, at the Director's discretion, may provide performance bonuses to any Secret Service agent, officer, or analyst who demonstrates exemplary service.

(2) RETENTION BONUSES.—The Director may provide retention bonuses to any Secret Service agent, officer, or analyst who commits to 2 years of additional service with the Secret Service.

(3) SIGNING BONUSES.—The Director may provide a signing bonus to any Secret Service agent, officer, or analyst who—

(A) is hired on or after the date of the enactment of this Act; and

(B) commits to 5 years of service with the United States Secret Service.

(4) SERVICE AGREEMENT.—In providing a retention or signing bonus under this subsection, the Director shall provide each qualifying individual with a written service agreement that includes—

(A) the commencement and termination dates of the required service period (or provisions for the determination of such dates);

(B) the amount of the bonus; and

(C) any other term or condition under which the bonus is payable, subject to the requirements under this subsection, including—

(i) the conditions under which the agreement may be terminated before the agreed-upon service period has been completed; and

(ii) the effect of a termination described in clause (i).

Subtitle B—Judiciary Matters

SEC. 100101. APPROPRIATION TO THE ADMINISTRATIVE OFFICE OF THE UNITED STATES COURTS.

In addition to amounts otherwise available, there is appropriated to the Director of the Administrative Office of the United States Courts, out of amounts in the Treasury not otherwise appropriated, $1,250,000 for each of fiscal years 2025 through 2028, for the purpose of continuing analyses and reporting pursuant to section 604(a)(2) of title 28, United States Code, to examine the state of the dockets of the courts and to prepare and transmit statistical data and reports as to the business of the courts, including an assessment of the number, frequency, and related metrics of judicial orders issuing non-party relief against the Federal Government and their aggregate cost impact on the taxpayers of the United States, as determined by each court when imposing securities for the issuance of preliminary injunctions or temporary restraining orders against the Federal Government pursuant to rule 65(c) of the Federal Rules of Civil Procedure.

SEC. 100102. APPROPRIATION TO THE FEDERAL JUDICIAL CENTER.

(a) APPROPRIATION.—In addition to amounts otherwise available, there is appropriated to the Director of the Federal Judicial Center, out of amounts in the Treasury not otherwise appropriated, $1,000,000 for each of fiscal years 2025 through 2028, for the purpose described in subsection (b).

(b) USE OF FUNDS.—The Federal Judicial Center shall use the amounts appropriated under subsection (a) for the continued implementation of programs pursuant to section 620(b)(3) of title 28, United States Code, to stimulate, create, develop, and conduct programs of continuing education and training for personnel of the judicial branch, including training on the absence of constitutional and statutory authority supporting legal claims that seek non-party relief against the Federal Government, and strategic approaches for mitigating the aggregate cost impact of such legal claims on the taxpayers of the United States.

Subtitle C—Radiation Exposure Compensation Matters

SEC. 100201. EXTENSION OF FUND.

Section 3(d) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) by striking the first sentence and inserting "The Fund shall terminate on December 31, 2028."; and

(2) by striking "the end of that 2-year period" and inserting "such date".

SEC. 100202. CLAIMS RELATING TO ATMOSPHERIC TESTING.

(a) LEUKEMIA CLAIMS RELATING TO TRINITY TEST IN NEW MEXICO AND TESTS AT THE NEVADA SITE.—Section 4(a)(1)(A) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) in clause (i)—

(A) in subclause (I), by striking "October 31, 1958" and inserting "November 6, 1962";

(B) in subclause (II)—

(i) by striking "in the affected area" and inserting "in an affected area"; and

(ii) by striking "or" after the semicolon;

(C) by redesignating subclause (III) as subclause (IV); and

(D) by inserting after subclause (II) the following:

"(III) was physically present in an affected area for a period of at least 1 year during the period beginning on September 24, 1944, and ending on November 6, 1962; or"; and

(2) in clause (ii)(I), by striking "physical presence described in subclause (I) or (II) of clause (i) or onsite participation described in clause (i)(III)" and inserting "physical presence described in subclause (I), (II), or (III) of clause (i) or onsite participation described in clause (i)(IV)".

(b) AMOUNTS FOR CLAIMS RELATED TO LEUKEMIA.—Section 4(a)(1) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) in subparagraph (A), by striking "an amount" and inserting "the amount";

(2) by striking subparagraph (B) and inserting the following:

"(B) AMOUNT.—If the conditions described in subparagraph (C) are met, an individual who is described in subparagraph (A) shall receive $100,000."; and

(3) in subparagraph (C), by adding at the end the following:

"(iv) No payment under this paragraph previously has been made to the individual, on behalf of the individual, or to a survivor of the individual.".

(c) CONDITIONS FOR CLAIMS RELATED TO LEUKEMIA.—Section 4(a)(1)(C) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) by striking clause (i); and

(2) by redesignating clauses (ii) and (iii) as clauses (i) and (ii), respectively.

(d) SPECIFIED DISEASES CLAIMS RELATING TO TRINITY TEST IN NEW MEXICO AND TESTS AT THE NEVADA SITE.—Section 4(a)(2) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) in subparagraph (A)—

(A) by striking "in the affected area" and inserting "in an affected area";

(B) by striking "2 years" and inserting "1 year"; and

(C) by striking "October 31, 1958," and inserting "November 6, 1962;";

(2) in subparagraph (B)—

(A) by striking "in the affected area" and inserting "in an affected area"; and

(B) by striking ", or" at the end and inserting a semicolon;

(3) by redesignating subparagraph (C) as subparagraph (D); and

(4) by inserting after subparagraph (B) the following:

"(C) was physically present in an affected area for a period of at least 1 year during the period beginning on September 24, 1944, and ending on November 6, 1962; or".

(e) AMOUNTS FOR CLAIMS RELATED TO SPECIFIED DISEASES.—Section 4(a)(2) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended in the matter following subparagraph (D) (as redesignated by subsection (d) of this section)—

(1) by striking "$50,000 (in the case of an individual described in subparagraph (A) or (B)) or $75,000 (in the case of an individual described in subparagraph (C))," and inserting "$100,000";

(2) in clause (i), by striking ", and" and inserting a semicolon;

(3) in clause (ii), by striking the period at the end and inserting "; and"; and

(4) by adding at the end the following:

"(iii) no payment under this paragraph previously has been made to the individual, on behalf of the individual, or to a survivor of the individual.".

(f) DOWNWIND STATES.—Section 4(b)(1) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended to read as follows:

"(1) 'affected area' means—

"(A) except as provided under subparagraph (B)—

"(i) the States of New Mexico, Utah, and Idaho;

"(ii) in the State of Nevada, the counties of White Pine, Nye, Lander, Lincoln, Eureka, and that portion of Clark County that consists of townships 13 through 16 at ranges 63 through 71; and

"(iii) in the State of Arizona, the counties of Coconino, Yavapai, Navajo, Apache, and Gila, and Mohave; and

"(B) with respect to a claim by an individual under subsection (a)(1)(A)(i)(III) or subsection (a)(2)(C), only New Mexico; and".

SEC. 100203. CLAIMS RELATING TO URANIUM MINING.

(a) EMPLOYEES OF MINES AND MILLS.—Section 5(a)(1)(A)(i) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended to read as follows:

"(i)(I) was employed in a uranium mine or uranium mill (including any individual who was employed in the transport of uranium ore or vanadium-uranium ore from such mine or mill) located in Colorado, New Mexico, Arizona, Wyoming, South Dakota, Washington, Utah, Idaho, North Dakota, Oregon, or Texas at any time during the period beginning on January 1, 1942, and ending on December 31, 1990; or

"(II) was employed as a core driller in a State referred to in subclause (I) during the period described in such subclause; and".

(b) MINERS.—Section 5(a)(1)(A)(ii)(I) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended by inserting "or renal cancer or any other chronic renal disease, including nephritis and kidney tubal tissue injury" after "nonmalignant respiratory disease".

(c) MILLERS, CORE DRILLERS, AND ORE TRANSPORTERS.—Section 5(a)(1)(A)(ii)(II) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) by inserting ", core driller," after "was a miller";

(2) by inserting ", or was involved in remediation efforts at such a uranium mine or uranium mill," after "ore transporter";

(3) by inserting "(I)" after "clause (i)"; and

(4) by striking "or renal cancers" and all that follows and inserting "or renal cancer or any other chronic renal disease, including nephritis and kidney tubal tissue injury; or".

(d) COMBINED WORK HISTORIES.—Section 5(a)(1)(A)(ii) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note), as amended by subsection (c), is further amended—

(1) in subclause (I), by striking "or" at the end; and

(2) by adding at the end the following:

"(III)(aa) does not meet the conditions of subclause (I) or (II);

"(bb) worked, during the period described in clause (i)(I), in 2 or more of the following positions: miner, miller, core driller, and ore transporter;

"(cc) meets the requirements under paragraph (4) or (5); and

"(dd) submits written medical documentation that the individual developed lung cancer, a nonmalignant respiratory disease, renal cancer, or any other chronic renal disease, including nephritis and kidney tubal tissue injury after exposure to radiation through work in one or more of the positions referred to in item (bb);".

(e) SPECIAL RULES RELATING TO COMBINED WORK HISTORIES.—Section 5(a) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended by adding at the end the following:

"(4) SPECIAL RULE RELATING TO COMBINED WORK HISTORIES FOR INDIVIDUALS WITH AT LEAST ONE YEAR OF EXPERIENCE.—An individual meets the requirements under this paragraph if the individual worked in one or more of the positions referred to in paragraph (1)(A)(ii)(III)(bb) for a period of at least one year during the period described in paragraph (1)(A)(i)(I).

"(5) SPECIAL RULE RELATING TO COMBINED WORK HISTORIES FOR MINERS.—An individual meets the requirements of this paragraph if the individual, during the period described in paragraph (1)(A)(i)(I), worked as a miner and was exposed to such number of working level months that the Attorney General determines, when combined with the exposure of such individual to radiation through work as a miller, core driller, or ore transporter during the period described in paragraph (1)(A)(i)(I), results in such individual being exposed to a total level of radiation that is greater or equal to the level of exposure of an individual described in paragraph (4).".

(f) DEFINITION OF CORE DRILLER.—Section 5(b) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended—

(1) in paragraph (7), by striking "and" at the end;

(2) in paragraph (8), by striking the period at the end and inserting "; and"; and

(3) by adding at the end the following:

"(9) the term 'core driller' means any individual employed to engage in the act or process of obtaining cylindrical rock samples of uranium or vanadium by means of a borehole drilling machine for the purpose of mining uranium or vanadium.".

SEC. 100204. CLAIMS RELATING TO MANHATTAN PROJECT WASTE.

The Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended by inserting after section 5 the following:

"SEC. 5A. CLAIMS RELATING TO MANHATTAN PROJECT WASTE.

"(a) IN GENERAL.—A claimant shall receive compensation for a claim made under this Act, as described in subsection (b) or (c), if—

"(1) a claim for compensation is filed with the Attorney General—

"(A) by an individual described in paragraph (2); or

"(B) on behalf of that individual by an authorized agent of that individual, if the individual is deceased or incapacitated, such as—

"(i) an executor of estate of that individual; or

"(ii) a legal guardian or conservator of that individual;

"(2) that individual, or if applicable, an authorized agent of that individual, demonstrates that such individual—

"(A) was physically present in an affected area for a period of at least 2 years after January 1, 1949; and

"(B) contracted a specified disease after such period of physical presence;

"(3) the Attorney General certifies that the identity of that individual, and if applicable, the authorized agent of that individual, is not fraudulent or otherwise misrepresented; and

"(4) the Attorney General determines that the claimant has satisfied the applicable requirements of this Act.

"(b) LOSSES AVAILABLE TO LIVING AFFECTED INDIVIDUALS.—

"(1) IN GENERAL.—In the event of a claim qualifying for compensation under subsection (a) that is submitted to the Attorney General to be eligible for compensation under this section at a time when the individual described in subsection (a)(2) is living, the amount of compensation under this section shall be in an amount that is the greater of $50,000 or the total amount of compensation for which the individual is eligible under paragraph (2).

"(2) LOSSES DUE TO MEDICAL EXPENSES.—A claimant described in paragraph (1) shall be eligible to receive, upon submission of contemporaneous written medical records, reports, or billing statements created by or at the direction of a licensed medical professional who provided contemporaneous medical care to the claimant, additional compensation in the amount of all documented out-of-pocket medical expenses incurred as a result of the specified disease suffered by that claimant, such as any medical expenses not covered, paid for, or reimbursed through—

"(A) any public or private health insurance;

"(B) any employee health insurance;

"(C) any workers' compensation program; or

"(D) any other public, private, or employee health program or benefit.

"(3) LIMITATION.—No claimant is eligible to receive compensation under this subsection with respect to medical expenses unless the submissions described in paragraph (2) with respect to such expenses are submitted on or before December 31, 2028.

"(c) PAYMENTS TO BENEFICIARIES OF DECEASED INDIVIDUALS.—In the event that an individual described in subsection (a)(2) who qualifies for compensation under subsection (a) is deceased at the time of submission of the claim—

"(1) a surviving spouse may, upon submission of a claim and records sufficient to satisfy the requirements of subsection (a) with respect to the deceased individual, receive compensation in the amount of $25,000; or

"(2) in the event that there is no surviving spouse, the surviving children, minor or otherwise, of the deceased individual may, upon submission of a claim and records sufficient to satisfy the requirements of subsection (a) with respect to the deceased individual, receive compensation in the total amount of $25,000, paid in equal shares to each surviving child.

"(d) AFFECTED AREAS.—For purposes of this section, the term 'affected area' means—

"(1) in the State of Missouri, the ZIP Codes of 63031, 63033, 63034, 63042, 63045, 63074, 63114, 63135, 63138, 63044, 63121, 63140, 63145, 63147, 63102, 63304, 63134, 63043, 63341, 63368, and 63367;

"(2) in the State of Tennessee, the ZIP Codes of 37716, 37840, 37719, 37748, 37763, 37828, 37769, 37710, 37845, 37887, 37829, 37854, 37830, and 37831;

"(3) in the State of Alaska, the ZIP Codes of 99546 and 99547; and

"(4) in the State of Kentucky, the ZIP Codes of 42001, 42003, and 42086.

"(e) SPECIFIED DISEASE.—For purposes of this section, the term 'specified disease' means any of the following:

"(1) Any leukemia, provided that the initial exposure occurred after 20 years of age and the onset of the disease was at least 2 years after first exposure.

"(2) Any of the following diseases, provided that the onset was at least 2 years after the initial exposure:

"(A) Multiple myeloma.

"(B) Lymphoma, other than Hodgkin's disease.

"(C) Primary cancer of the—

"(i) thyroid;

"(ii) male or female breast;

"(iii) esophagus;

"(iv) stomach;

"(v) pharynx;

"(vi) small intestine;

"(vii) pancreas;
"(viii) bile ducts;
"(ix) gall bladder;
"(x) salivary gland;
"(xi) urinary bladder;
"(xii) brain;
"(xiii) colon;
"(xiv) ovary;
"(xv) bone;
"(xvi) renal;
"(xvii) liver, except if cirrhosis or hepatitis B is indicated; or
"(xviii) lung.

"(f) PHYSICAL PRESENCE.—

"(1) IN GENERAL.—For purposes of this section, the Attorney General may not determine that a claimant has satisfied the requirements under subsection (a) unless demonstrated by submission of—

"(A) contemporaneous written residential documentation or at least 1 additional employer-issued or government-issued document or record that the claimant, for at least 2 years after January 1, 1949, was physically present in an affected area; or

"(B) other documentation determined by the Attorney General to demonstrate that the claimant, for at least 2 years after January 1, 1949, was physically present in an affected area.

"(2) TYPES OF PHYSICAL PRESENCE.—For purposes of determining physical presence under this section, a claimant shall be considered to have been physically present in an affected area if—

"(A) the claimant's primary residence was in the affected area;

"(B) the claimant's place of employment was in the affected area; or

"(C) the claimant attended school in the affected area.

"(g) DISEASE CONTRACTION IN AFFECTED AREAS.—For purposes of this section, the Attorney General may not determine that a claimant has satisfied the requirements under subsection (a) unless the claimant submits—

"(1) written medical records or reports created by or at the direction of a licensed medical professional, created contemporaneously with the provision of medical care to the claimant, that the claimant, after a period of physical presence in an affected area, contracted a specified disease; or

"(2) other documentation determined by the Attorney General to demonstrate that the claimant contracted a specified disease after a period of physical presence in an affected area.".

SEC. 100205. LIMITATIONS ON CLAIMS.

Section 8(a) of the Radiation Exposure Compensation Act (Public Law 101–426; 42 U.S.C. 2210 note) is amended by striking "2 years after the date of enactment of the RECA Extension Act of 2022" and inserting "December 31, 2027".

Speaker of the House of Representatives.

Vice President of the United States and President of the Senate.

CHAPTER 2024-186

Committee Substitute for Committee Substitute for House Bill No. 1645

An act relating to energy resources; creating s. 163.3210, F.S.; providing legislative intent; providing definitions; allowing resiliency facilities in certain land use categories in local government comprehensive plans and specified districts if certain criteria are met; allowing local governments to adopt ordinances for resiliency facilities if certain requirements are met; prohibiting amendments to a local government's comprehensive plan, land use map, zoning districts, or land development regulations in a manner that would conflict with resiliency facility classification after a specified date; amending s. 286.29, F.S.; revising energy guidelines for public businesses; eliminating the requirement that the Department of Management Services develop and maintain the Florida Climate-Friendly Preferred Products List; eliminating the requirement that state agencies contract for meeting and conference space only with facilities that have a Green Lodging designations; eliminating the requirement that state agencies, state universities, community colleges, and local governments that procure new vehicles under a state purchasing plan select certain vehicles under a specified circumstance; amending s. 366.032, F.S.; including community development districts as a type of political subdivision for purposes of preemption over utility service restrictions; creating s. 366.042, F.S.; requiring rural electric cooperatives and municipal electric utilities to enter into and maintain at least one mutual aid agreement or pre-event agreement with certain entities for purposes of restoring power after a natural disaster; requiring rural electric cooperatives and municipal electric utilities to annually submit attestations of compliance to the Public Service Commission; providing construction; requiring the commission to compile the attestations and annually submit a copy of such attestations to the Division of Emergency Management; providing that the submission of such attestations makes rural electric cooperatives and municipal electric utilities eligible to receive state financial assistance; providing that if such attestations are not submitted, rural electric cooperatives and municipal electric utilities are not eligible to receive state financial assistance; providing construction; creating s. 366.057, F.S.; requiring public utilities to provide notice to the commission of certain power plant retirements within a specified timeframe; authorizing the commission to schedule hearings within a specified timeframe to make certain determinations on such plant retirements; specifying information to be provided by public utilities at the hearing; amending s. 366.94, F.S.; removing terminology; authorizing the commission to approve voluntary electric vehicle charging programs upon petition of a public utility, to become effective on or after a specified date, if certain requirements are met; providing applicability; amending s. 403.503, F.S.; defining the term "gross capacity"; creating s. 366.99, F.S.; providing definitions; authorizing public utilities to submit to the commission a petition for a proposed

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cost recovery for certain natural gas facilities relocation costs; requiring the commission to conduct annual proceedings to determine each utility's prudently incurred natural gas facilities relocation costs and to allow for the recovery of such costs; providing requirements for the commission's review; providing requirements for the allocation of such recovered costs; requiring the commission to adopt rules; providing a timeframe for such rulemaking; amending s. 377.601, F.S.; revising legislative intent; amending s. 377.6015, F.S.; revising the powers and duties of the Department of Agriculture and Consumer Services; conforming provisions to changes made by the act; amending s. 377.703, F.S.; revising additional functions of the department relating to energy resources; conforming provisions to changes made by the act; creating s. 377.708, F.S.; providing definitions; prohibiting the construction or expansion of certain wind energy facilities and wind turbines in the state; requiring the Department of Environmental Protection to review applications for federal wind energy leases in territorial waters of the United States adjacent to water of this state and signify its approval or objection to such applications; authorizing the department to seek injunctive relief for violations; repealing s. 377.801, F.S., relating to the Florida Energy and Climate Protection Act; repealing s. 377.802, F.S., relating to the purpose of the act; repealing s. 377.803, F.S., relating to definitions under the act; repealing s. 377.804, F.S., relating to the Renewable Energy and Energy-Efficient Technologies Grants Program; repealing s. 377.808, F.S., relating to the Florida Green Government Grants Act; repealing s. 377.809, F.S., relating to the Energy Economic Zone Pilot Program; repealing s. 377.816, F.S., relating to the Qualified Energy Conservation Bond Allocation Program; prohibiting the approval of new or additional applications, certifications, or allocations under such programs; prohibiting new contracts, agreements, and awards under such programs; rescinding all certifications or allocations issued under such programs; providing an exception; providing application relating to existing contracts or agreements under such programs; amending ss. 220.193, 288.9606, and 380.0651, F.S.; conforming provisions to changes made by the act; amending s. 403.9405, F.S.; revising the applicability of the Natural Gas Transmission Pipeline Siting Act; amending s. 720.3075, F.S.; prohibiting certain homeowners' association documents from precluding certain types or fuel sources of energy production and the use of certain appliances; requiring the commission to coordinate, develop, and recommend a plan under which an assessment of the security and resiliency of the state's electric grid and natural gas facilities against physical threats and cyber threats may be conducted; requiring the commission to consult with the Division of Emergency Management and the Florida Digital Service; requiring cooperation from all operating facilities in the state relating to such plan; providing additional content requirements for such plan; requiring the commission to submit by a recommended plan by a specified date to the Governor and the Legislature; providing additional content requirements for such plan; requiring the commission to study and evaluate the technical and economic feasibility of using advanced nuclear power technologies to meet the electrical power needs of the state; requiring the commission to research means to encourage and foster the installation and use of such technologies at military installations in partnership with public utilities; requiring the commission to consult with the Department of Environmental Protection and the Division of Emergency Management; requiring the commission to submit by a specified date a report to the Governor and the Legislature that contains its findings and any additional recommendations for potential legislative or administrative actions; requiring the Department of Transportation, in consultation with the Office of Energy within the Department of Agriculture and Consumer Services, to study and evaluate the potential development of hydrogen fueling infrastructure to support hydrogen-powered vehicles; requiring the department to submit by a specified date a report to the Governor and the Legislature that contains its findings and recommendations for specified actions that may accommodate the future development of hydrogen fueling infrastructure; providing effective dates.

Be It Enacted by the Legislature of the State of Florida:

Section 1. Section 163.3210, Florida Statutes, is created to read:

<u>163.3210 Natural gas resiliency and reliability infrastructure.—</u>

<u>(1) It is the intent of the Legislature to maintain, encourage, and ensure adequate and reliable fuel sources for public utilities. The resiliency and reliability of fuel sources for public utilities is critical to the state's economy; the ability of the state to recover from natural disasters; and the health, safety, welfare, and quality of life of the residents of the state.</u>

<u>(2) As used in this section, the term:</u>

<u>(a) "Natural gas" means all forms of fuel commonly or commercially known or sold as natural gas, including compressed natural gas and liquefied natural gas.</u>

<u>(b) "Natural gas reserve" means a facility that is capable of storing and transporting and, when operational, actively stores and transports a supply of natural gas.</u>

<u>(c) "Public utility" has the same meaning as defined in s. 366.02.</u>

<u>(d) "Resiliency facility" means a facility owned and operated by a public utility for the purposes of assembling, creating, holding, securing, or deploying natural gas reserves for temporary use during a system outage or natural disaster.</u>

<u>(3) A resiliency facility is a permitted use in all commercial, industrial, and manufacturing land use categories in a local government comprehensive plan and all commercial, industrial, and manufacturing districts. A resiliency facility must comply with the setback and landscape criteria for</u>

other similar uses. A local government may adopt an ordinance specifying buffer and landscaping requirements for resiliency facilities, provided such requirements do not exceed the requirements for similar uses involving the construction of other facilities that are permitted uses in commercial, industrial, and manufacturing land use categories and zoning districts.

(4) After July 1, 2024, a local government may not amend its comprehensive plan, land use map, zoning districts, or land development regulations in a manner that would conflict with a resiliency facility's classification as a permitted and allowable use, including, but not limited to, an amendment that causes a resiliency facility to be a nonconforming use, structure, or development.

Section 2. Section 286.29, Florida Statutes, is amended to read:

286.29 Energy guidelines for ~~Climate-friendly~~ public business.~~—The Legislature recognizes the importance of leadership by state government in the area of energy efficiency and in reducing the greenhouse gas emissions of state government operations. The following shall pertain to all state agencies when conducting public business:~~

~~(1) The Department of Management Services shall develop the "Florida Climate-Friendly Preferred Products List." In maintaining that list, the department, in consultation with the Department of Environmental Protection, shall continually assess products currently available for purchase under state term contracts to identify specific products and vendors that offer clear energy efficiency or other environmental benefits over competing products. When procuring products from state term contracts, state agencies shall first consult the Florida Climate-Friendly Preferred Products List and procure such products if the price is comparable.~~

~~(2) State agencies shall contract for meeting and conference space only with hotels or conference facilities that have received the "Green Lodging" designation from the Department of Environmental Protection for best practices in water, energy, and waste efficiency standards, unless the responsible state agency head makes a determination that no other viable alternative exists.~~

(1)~~(3)~~ Each state agency shall ensure that all maintained vehicles meet minimum maintenance schedules shown to reduce fuel consumption, which include:

(a) Ensuring appropriate tire pressures and tread depth.~~;~~

(b) Replacing fuel filters and emission filters at recommended intervals.~~;~~

(c) Using proper motor oils.~~; and~~

(d) Performing timely motor maintenance.

Each state agency shall measure and report compliance to the Department of Management Services through the Equipment Management Information System database.

~~(4) When procuring new vehicles, all state agencies, state universities, community colleges, and local governments that purchase vehicles under a state purchasing plan shall first define the intended purpose for the vehicle and determine which of the following use classes for which the vehicle is being procured:~~

~~(a) State business travel, designated operator;~~

~~(b) State business travel, pool operators;~~

~~(c) Construction, agricultural, or maintenance work;~~

~~(d) Conveyance of passengers;~~

~~(e) Conveyance of building or maintenance materials and supplies;~~

~~(f) Off-road vehicle, motorcycle, or all-terrain vehicle;~~

~~(g) Emergency response; or~~

~~(h) Other.~~

~~Vehicles described in paragraphs (a) through (h), when being processed for purchase or leasing agreements, must be selected for the greatest fuel efficiency available for a given use class when fuel economy data are available. Exceptions may be made for individual vehicles in paragraph (g) when accompanied, during the procurement process, by documentation indicating that the operator or operators will exclusively be emergency first responders or have special documented need for exceptional vehicle performance characteristics. Any request for an exception must be approved by the purchasing agency head and any exceptional performance characteristics denoted as a part of the procurement process prior to purchase.~~

(2)~~(5)~~ All state agencies shall use ethanol and biodiesel blended fuels when available. State agencies administering central fueling operations for state-owned vehicles shall procure biofuels for fleet needs to the greatest extent practicable.

Section 3. Subsections (1), (2), and (5) of section 366.032, Florida Statutes, are amended to read:

366.032 Preemption over utility service restrictions.—

(1) A municipality, county, special district, community development district created pursuant to chapter 190, or other political subdivision of the state may not enact or enforce a resolution, ordinance, rule, code, or policy or take any action that restricts or prohibits or has the effect of restricting or prohibiting the types or fuel sources of energy production which may be

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used, delivered, converted, or supplied by the following entities to serve customers that such entities are authorized to serve:

(a) A public utility or an electric utility as defined in this chapter;

(b) An entity formed under s. 163.01 that generates, sells, or transmits electrical energy;

(c) A natural gas utility as defined in s. 366.04(3)(c);

(d) A natural gas transmission company as defined in s. 368.103; or

(e) A Category I liquefied petroleum gas dealer or Category II liquefied petroleum gas dispenser or Category III liquefied petroleum gas cylinder exchange operator as defined in s. 527.01.

(2) Except to the extent necessary to enforce the Florida Building Code adopted pursuant to s. 553.73 or the Florida Fire Prevention Code adopted pursuant to s. 633.202, a municipality, county, special district, community development district created pursuant to chapter 190, or other political subdivision of the state may not enact or enforce a resolution, an ordinance, a rule, a code, or a policy or take any action that restricts or prohibits or has the effect of restricting or prohibiting the use of an appliance, including a stove or grill, which uses the types or fuel sources of energy production which may be used, delivered, converted, or supplied by the entities listed in subsection (1). As used in this subsection, the term “appliance” means a device or apparatus manufactured and designed to use energy and for which the Florida Building Code or the Florida Fire Prevention Code provides specific requirements.

(5) Any municipality, county, special district, community development district created pursuant to chapter 190, or political subdivision charter, resolution, ordinance, rule, code, policy, or action that is preempted by this act that existed before or on July 1, 2021, is void.

Section 4. Section 366.042, Florida Statutes, is created to read:

366.042 Mutual aid agreements of rural electric cooperatives and municipal electric utilities.—

(1) For the purposes of restoring power following a natural disaster that is subject to a state of emergency declared by the Governor, all rural electric cooperatives and municipal electric utilities shall enter into and maintain, at a minimum, one of the following:

(a) A mutual aid agreement with a municipal electric utility;

(b) A mutual aid agreement with a rural electric cooperative;

(c) A mutual aid agreement with a public utility; or

(d) A pre-event agreement with a private contractor.

(2) All rural electric cooperatives and municipal electric utilities operating in this state shall annually submit to the commission an attestation, in conformity with s. 92.525, stating that the organization has complied with the requirements of this section on or before May 15. Nothing in this section shall be construed to give the commission jurisdiction over the terms and conditions of a mutual aid agreement or agreement with a private contractor entered into by a rural electric cooperative or a municipal electric utility.

(3) The commission shall compile the attestations and annually submit a copy to the Division of Emergency Management no later than May 30.

(4) A rural electric cooperative or municipal electric utility that submits the attestation required by this section is eligible to receive state financial assistance, if such funding is available, for power restoration efforts following a natural disaster that is subject to a state of emergency declared by the Governor.

(5) A rural electric cooperative or municipal electric utility that does not submit an attestation required by this section is ineligible to receive state financial assistance for power restoration efforts following a natural disaster that is subject to a state of emergency declared by the Governor, until such time as the attestation is submitted.

(6) Nothing in this section shall be construed to prohibit, limit, or disqualify a rural electric cooperative or municipal electric utility from receiving funding under The Stafford Act, 42 U.S.C. 5121 et seq., or any other federal program, including programs administered by the state.

(7) This section does not expand or alter the jurisdiction of the commission over public utilities or electric utilities.

Section 5. Section 366.057, Florida Statutes, is created to read:

366.057 Retirement of electrical power plants.—A public utility shall provide notice to the commission at least 90 days before the full retirement of an electrical power plant if the date of such retirement does not coincide with the retirement date in the public utility's most recently approved depreciation study. No later than 90 days after such notice, the commission may schedule a hearing to determine whether retirement of the plant is prudent and consistent with the state's energy policy goals in s. 377.601(2). At a hearing scheduled under this section, the utility shall present its proposed retirement date for the plant, remaining depreciation expense on the plant, any other costs to be recovered in relation to the plant, and any planned replacement capacity.

Section 6. Subsection (4) is added to Section 366.94, Florida Statutes, to read:

366.94 Electric vehicle charging ~~stations~~.—

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(4) Upon petition of a public utility, the commission may approve voluntary electric vehicle charging programs to become effective on or after January 1, 2025, to include, but not be limited to, residential, fleet, and public electric vehicle charging, upon a determination by the commission that the utility's general body of ratepayers, as a whole, will not pay to support recovery of its electric vehicle charging investment by the end of the useful life of the assets dedicated to the electric vehicle charging service. This provision does not preclude cost recovery for electric vehicle charging programs approved by the commission before January 1, 2024.

Section 7. Present subsections (17) through (31) of section 403.503, Florida Statutes, are redesignated as subsections (18) through (32), respectively, and a new subsection (17) is added to that section, to read:

403.503 Definitions relating to Florida Electrical Power Plant Siting Act. As used in this act:

(17) "Gross capacity" means, for a steam facility, the maximum generating capacity based on nameplate generator rating, and for a solar electrical generating facility, the capacity measured as alternating current which is independently metered prior to the point of interconnection to the transmission grid.

Section 8. Section 366.99, Florida Statutes, is created to read:

366.99 Natural gas facilities relocation costs.—

(1) As used in this section, the term:

(a) "Authority" has the same meaning as in s. 337.401(1)(a).

(b) "Facilities relocation" means the physical moving, modification, or reconstruction of public utility facilities to accommodate the requirements imposed by an authority.

(c) "Natural gas facilities" or "facilities" means gas mains, laterals, and service lines used to distribute natural gas to customers. The term includes all ancillary equipment needed for safe operations, including, but not limited to, regulating stations, meters, other measuring devices, regulators, and pressure monitoring equipment.

(d) "Natural gas facilities relocation costs" means the costs to relocate or reconstruct facilities as required by a mandate, a statute, a law, an ordinance, or an agreement between the utility and an authority, including, but not limited to, costs associated with reviewing plans provided by an authority. The term does not include any costs recovered through the public utility's base rates.

(e) "Public utility" or "utility" has the same meaning as in s. 366.02, except that the term does not include an electric utility.

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(2) A utility may submit to the commission, pursuant to commission rule, a petition describing the utility's projected natural gas facilities relocation costs for the next calendar year, actual natural gas facilities relocation costs for the prior calendar year, and proposed cost-recovery factors designed to recover such costs. A utility's decision to proceed with implementing a plan before filing such a petition does not constitute imprudence.

(3) The commission shall conduct an annual proceeding to determine each utility's prudently incurred natural gas facilities relocation costs and to allow each utility to recover such costs through a charge separate and apart from base rates, to be referred to as the natural gas facilities relocation cost recovery clause. The commission's review in the proceeding is limited to determining the prudence of the utility's actual incurred natural gas facilities relocation costs and the reasonableness of the utility's projected natural gas facilities relocation costs for the following calendar year; and providing for a true-up of the costs with the projections on which past factors were set. The commission shall require that any refund or collection made as a part of the true-up process includes interest.

(4) All costs approved for recovery through the natural gas facilities relocation cost recovery clause must be allocated to customer classes pursuant to the rate design most recently approved by the commission.

(5) If a capital expenditure is recoverable as a natural gas facilities relocation cost, the public utility may recover the annual depreciation on the cost, calculated at the public utility's current approved depreciation rates, and a return on the undepreciated balance of the costs at the public utility's weighted average cost of capital using the last approved return on equity.

(6) The commission shall adopt rules to implement and administer this section and shall propose a rule for adoption as soon as practicable after July 1, 2024.

Section 9. Section 377.601, Florida Statutes, is amended to read:

377.601 Legislative intent.—

(1) The purpose of the state's energy policy is to ensure an adequate, reliable, and cost-effective supply of energy for the state in a manner that promotes the health and welfare of the public and economic growth. The Legislature intends that governance of the state's energy policy be efficiently directed toward achieving this purpose. ~~The Legislature finds that the state's energy security can be increased by lessening dependence on foreign oil; that the impacts of global climate change can be reduced through the reduction of greenhouse gas emissions; and that the implementation of alternative energy technologies can be a source of new jobs and employment opportunities for many Floridians. The Legislature further finds that the state is positioned at the front line against potential impacts of global climate change. Human and economic costs of those impacts can be averted by global actions and, where necessary, adapted to by a concerted effort to~~

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~~make Florida's communities more resilient and less vulnerable to these impacts. In focusing the government's policy and efforts to benefit and protect our state, its citizens, and its resources, the Legislature believes that a single government entity with a specific focus on energy and climate change is both desirable and advantageous. Further, the Legislature finds that energy infrastructure provides the foundation for secure and reliable access to the energy supplies and services on which Florida depends. Therefore, there is significant value to Florida consumers that comes from investment in Florida's energy infrastructure that increases system reliability, enhances energy independence and diversification, stabilizes energy costs, and reduces greenhouse gas emissions.~~

<u>(2) For the purposes of subsection (1), the state's energy policy must be guided by the following goals:</u>

<u>(a) Ensuring a cost-effective and affordable energy supply.</u>

<u>(b) Ensuring adequate supply and capacity.</u>

<u>(c) Ensuring a secure, resilient, and reliable energy supply, with an emphasis on a diverse supply of domestic energy resources.</u>

<u>(d) Protecting public safety.</u>

<u>(e) Protecting the state's natural resources, including its coastlines, tributaries, and waterways.</u>

<u>(f) Supporting economic growth.</u>

<u>(3)</u>~~(2)~~ <u>In furtherance of the goals in subsection (2),</u> it is the policy of the state ~~of Florida~~ to:

(a) ~~Develop and~~ Promote the <u>cost-effective development and</u> ~~effective~~ use of <u>a diverse supply of domestic</u> energy <u>resources</u> in the state <u>and</u>~~,~~ discourage ~~all forms of~~ energy waste~~, and recognize and address the potential of global climate change wherever possible~~.

(b) <u>Promote the cost-effective development and maintenance of energy infrastructure that is resilient to natural and manmade threats to the security and reliability of the state's energy supply</u> ~~Play a leading role in developing and instituting energy management programs aimed at promoting energy conservation, energy security, and the reduction of greenhouse gas emissions~~.

<u>(c) Reduce reliance on foreign energy resources.</u>

<u>(d)</u>~~(c)~~ Include energy <u>reliability and security</u> considerations in all state, regional, and local planning.

<u>(e)</u>~~(d)~~ Utilize and manage effectively energy resources used within state agencies.

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(f)~~(e)~~ Encourage local governments to include energy considerations in all planning and to support their work in promoting energy management programs.

(g)~~(f)~~ Include the full participation of citizens in the development and implementation of energy programs.

(h)~~(g)~~ Consider in its decisions the energy needs of each economic sector, including residential, industrial, commercial, agricultural, and governmental uses, and reduce those needs whenever possible.

(i)~~(h)~~ Promote energy education and the public dissemination of information on energy and its impacts in relation to the goals in subsection (2) ~~environmental, economic, and social impact~~.

(j)~~(i)~~ Encourage the research, development, demonstration, and application of domestic energy resources, including the use of ~~alternative energy resources, particularly~~ renewable energy resources.

(k)~~(j)~~ Consider, in its decisionmaking, the impacts of energy-related activities on the goals in subsection (2) ~~social, economic, and environmental impacts of energy-related activities~~, including the whole-life-cycle impacts of any potential energy use choices, so that detrimental effects of these activities are understood and minimized.

(l)~~(k)~~ Develop and maintain energy emergency preparedness plans to minimize the effects of an energy shortage within this state ~~Florida~~.

Section 10. Subsection (2) of section 377.6015, Florida Statutes, is amended to read:

377.6015 Department of Agriculture and Consumer Services; powers and duties.—

(2) The department shall:

~~(a) Administer the Florida Renewable Energy and Energy-Efficient Technologies Grants Program pursuant to s. 377.804 to assure a robust grant portfolio.~~

(a)~~(b)~~ Develop policy for requiring grantees to provide royalty-sharing or licensing agreements with state government for commercialized products developed under a state grant.

~~(c) Administer the Florida Green Government Grants Act pursuant to s. 377.808 and set annual priorities for grants.~~

(b)~~(d)~~ Administer the information gathering and reporting functions pursuant to ss. 377.601-377.608.

~~(e) Administer the provisions of the Florida Energy and Climate Protection Act pursuant to ss. 377.801-377.804~~.

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(c)~~(f)~~ Advocate for energy ~~and climate change~~ issues consistent with the goals in s. 377.601(2) and provide educational outreach and technical assistance in cooperation with the state's academic institutions.

(d)~~(g)~~ Be a party in the proceedings to adopt goals and submit comments to the Public Service Commission pursuant to s. 366.82.

(e)~~(h)~~ Adopt rules pursuant to chapter 120 in order to implement all powers and duties described in this section.

Section 11. Subsection (1) and paragraphs (e), (f), (h), and (m) of subsection (2) of section 377.703, Florida Statutes, are amended to read:

377.703 Additional functions of the Department of Agriculture and Consumer Services.—

(1) LEGISLATIVE INTENT.—Recognizing that energy supply and demand questions have become a major area of concern to the state which must be dealt with by effective and well-coordinated state action, it is the intent of the Legislature to promote the efficient, effective, and economical management of energy problems, centralize energy coordination responsibilities, pinpoint responsibility for conducting energy programs, and ensure the accountability of state agencies for the implementation of s. 377.601 ~~s. 377.601(2)~~, the state energy policy. It is the specific intent of the Legislature that nothing in this act shall in any way change the powers, duties, and responsibilities assigned by the Florida Electrical Power Plant Siting Act, part II of chapter 403, or the powers, duties, and responsibilities of the Florida Public Service Commission.

(2) DUTIES.—The department shall perform the following functions, unless as otherwise provided, consistent with the development of a state energy policy:

(e) The department shall analyze energy data collected and prepare long-range forecasts of energy supply and demand in coordination with the Florida Public Service Commission, which is responsible for electricity and natural gas forecasts. To this end, the forecasts shall contain:

1. An analysis of the relationship of state economic growth and development to energy supply and demand, including the constraints to economic growth resulting from energy supply constraints.

2. ~~Plans for the development of renewable energy resources and reduction in dependence on depletable energy resources, particularly oil and natural gas, and~~ An analysis of the extent to which domestic energy resources, including renewable energy sources, are being utilized in this ~~the~~ state.

3. Consideration of alternative scenarios of statewide energy supply and demand for 5, 10, and 20 years to identify strategies for long-range action,

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including identification of potential impacts in relation to the goals in s. 377.601(2) ~~social, economic, and environmental effects~~.

4. An assessment of the state's energy resources, including examination of the availability of commercially developable and imported fuels, and an analysis of anticipated impacts in relation to the goals in s. 377.601(2) ~~effects on the state's environment and social services~~ resulting from energy resource development activities or from energy supply constraints, or both.

(f) The department shall submit an annual report to the Governor and the Legislature reflecting its activities and making recommendations for policies for improvement of the state's response to energy supply and demand and its effect on the health, safety, and welfare of the residents of this state. The report must include a report from the Florida Public Service Commission on electricity and natural gas and information on energy conservation programs conducted and underway in the past year and include recommendations for energy efficiency and conservation programs for the state, including:

1. Formulation of specific recommendations for improvement in the efficiency of energy utilization in governmental, residential, commercial, industrial, and transportation sectors.

2. Collection and dissemination of information relating to energy efficiency and conservation.

3. Development and conduct of educational and training programs relating to energy efficiency and conservation.

4. An analysis of the ways in which state agencies are seeking to implement s. 377.601 ~~s. 377.601(2)~~, the state energy policy, and recommendations for better fulfilling this policy.

(h) The department shall promote the development and use of renewable energy resources, in conformance with chapter 187 and s. 377.601, by:

~~1. Establishing goals and strategies for increasing the use of renewable energy in this state.~~

1.~~2.~~ Aiding and promoting the commercialization of renewable energy resources, in cooperation with the Florida Energy Systems Consortium; the Florida Solar Energy Center; and any other federal, state, or local governmental agency that may seek to promote research, development, and the demonstration of renewable energy equipment and technology.

2.~~3.~~ Identifying barriers to greater use of renewable energy resources in this state, and developing specific recommendations for overcoming identified barriers, with findings and recommendations to be submitted annually in the report to the Governor and Legislature required under paragraph (f).

3.~~4.~~ In cooperation with the Department of Environmental Protection, the Department of Transportation, the Department of Commerce, the Florida Energy Systems Consortium, the Florida Solar Energy Center, and the Florida Solar Energy Industries Association, investigating opportunities, pursuant to the national Energy Policy Act of 1992, the Housing and Community Development Act of 1992, and any subsequent federal legislation, for renewable energy resources, electric vehicles, and other renewable energy manufacturing, distribution, installation, and financing efforts that enhance this state's position as the leader in renewable energy research, development, and use.

4.~~5.~~ Undertaking other initiatives to advance the development and use of renewable energy resources in this state.

In the exercise of its responsibilities under this paragraph, the department shall seek the assistance of the renewable energy industry in this state and other interested parties and may enter into contracts, retain professional consulting services, and expend funds appropriated by the Legislature for such purposes.

(m) In recognition of the devastation to the economy of this state and the dangers to the health and welfare of residents of this state caused by severe hurricanes, and the potential for such impacts caused by other natural disasters, the Division of Emergency Management shall include in its energy emergency contingency plan and provide to the Florida Building Commission for inclusion in the Florida Energy Efficiency Code for Building Construction specific provisions to facilitate the use of cost-effective ~~solar~~ energy technologies as emergency remedial and preventive measures for providing electric power, street lighting, and water heating service in the event of electric power outages.

Section 12. Section 377.708, Florida Statutes, is created to read:

377.708 Wind energy.—

(1) DEFINITIONS.—As used in this section, the term:

(a) "Coastline" means the established line of mean high water.

(b) "Department" means the Department of Environmental Protection.

(c) "Offshore wind energy facility" means any wind energy facility located on waters of this state, including other buildings, structures, vessels, or electrical transmission cabling to be sited on waters of this state, or connected to corresponding onshore substations that are used to support the operation of one or more wind turbines sited or constructed on waters of this state and any submerged lands or territorial waters that are not under the jurisdiction of the state.

(d) "Real property" has the same meaning as provided in s. 192.001(12).

(e) "Vessel" has the same meaning as provided in s. 327.02.

(f) "Waters of this state" has the same meaning as provided in s. 327.02, except the term also includes all state submerged lands.

(g) "Wind energy facility" means an electrical wind generation facility or expansion thereof comprised of one or more wind turbines and including substations; meteorological data towers; aboveground, underground, and electrical transmission lines; and transformers, control systems, and other buildings or structures under common ownership or operating control used to support the operation of the facility the primary purpose of which is to offer electricity supply for sale.

(h) "Wind turbine" means a device or apparatus that has the capability to convert kinetic wind energy into rotational energy that drives an electrical generator, consisting of a tower body and rotator with two or more blades and capable of producing more than 10 kilowatts of electrical power. The term includes both horizontal and vertical axis turbines. The term does not include devices used to measure wind speed and direction, such as an anemometer.

(2) PROHIBITED ACTIVITIES.—

(a) Construction or expansion of the following is prohibited:

1. An offshore wind energy facility.

2. A wind turbine or wind energy facility on real property within 1 mile of coastline in this state.

3. A wind turbine or wind energy facility on real property within 1 mile of the Atlantic Intracoastal Waterway or Gulf Intracoastal Waterway.

4. A wind turbine or wind energy facility on waters of this state and any submerged lands.

(b) This subsection does not prohibit:

1. Affixation of a wind turbine directly to a vessel solely for the purpose of providing power to electronic equipment located onboard the vessel.

2. Operation of a wind turbine installed before July 1, 2024.

(3) REVIEW.—The department shall review all applications for federal wind energy leases in the territorial waters of the United States adjacent to waters of this state and shall signify its approval of or objection to each application.

(4) INJUNCTIVE RELIEF.—The department may bring an action for injunctive relief against any person who constructs or expands an offshore wind energy facility or a wind turbine in this state in violation of this section.

Section 13. Sections 377.801, 377.802, 377.803, 377.804, 377.808, 377.809, and 377.816, Florida Statutes, are repealed.

Section 14. (1) For programs established pursuant to s. 377.804, s. 377.808, s. 377.809, or s. 377.816, Florida Statutes, there may not be:

(a) New or additional applications, certifications, or allocations approved.

(b) New letters of certification issued.

(c) New contracts or agreements executed.

(d) New awards made.

(2) All certifications or allocations issued under such programs are rescinded except for the certifications of, or allocations to, those certified applicants or projects that continue to meet the applicable criteria in effect before July 1, 2024. Any existing contract or agreement authorized under any of these programs shall continue in full force and effect in accordance with the statutory requirements in effect when the contract or agreement was executed or last modified. However, further modifications, extensions, or waivers may not be made or granted relating to such contracts or agreements, except computations by the Department of Revenue of the income generated by or arising out of the qualifying project.

Section 15. Paragraph (d) of subsection (2) of section 220.193, Florida Statutes, is amended to read:

220.193 Florida renewable energy production credit.—

(2) As used in this section, the term:

(d) "Florida renewable energy facility" means a facility in the state that produces electricity for sale from renewable energy~~, as defined in s. 377.803~~.

Section 16. Subsection (7) of section 288.9606, Florida Statutes, is amended to read:

288.9606 Issue of revenue bonds.—

(7) Notwithstanding any provision of this section, the corporation in its corporate capacity may, without authorization from a public agency under s. 163.01(7), issue revenue bonds or other evidence of indebtedness under this section to:

(a) Finance the undertaking of any project within the state that promotes renewable energy as defined in s. 366.91 ~~or s. 377.803~~;

(b) Finance the undertaking of any project within the state that is a project contemplated or allowed under s. 406 of the American Recovery and Reinvestment Act of 2009; ~~or~~

(c) If permitted by federal law, finance qualifying improvement projects within the state under s. 163.08; or~~.~~

(d) Finance the costs of acquisition or construction of a transportation facility by a private entity or consortium of private entities under a public-private partnership agreement authorized by s. 334.30.

Section 17. Paragraph (w) of subsection (2) of section 380.0651, Florida Statutes, is amended to read:

380.0651 Statewide guidelines, standards, and exemptions.—

(2) STATUTORY EXEMPTIONS.—The following developments are exempt from s. 380.06:

~~(w) Any development in an energy economic zone designated pursuant to s. 377.809 upon approval by its local governing body.~~

If a use is exempt from review pursuant to paragraphs (a)-(u), but will be part of a larger project that is subject to review pursuant to s. 380.06(12), the impact of the exempt use must be included in the review of the larger project, unless such exempt use involves a development that includes a landowner, tenant, or user that has entered into a funding agreement with the state land planning agency under the Innovation Incentive Program and the agreement contemplates a state award of at least $50 million.

Section 18. Subsection (2) of section 403.9405, Florida Statutes, is amended to read:

403.9405 Applicability; certification; exemption; notice of intent.—

(2) ~~No construction of~~ A natural gas transmission pipeline may not be constructed ~~be undertaken after October 1, 1992,~~ without first obtaining certification under ss. 403.9401-403.9425, but these sections do not apply to:

(a) Natural gas transmission pipelines which are less than 100 ~~15~~ miles in length or which do not cross a county line, unless the applicant has elected to apply for certification under ss. 403.9401-403.9425.

(b) Natural gas transmission pipelines for which a certificate of public convenience and necessity has been issued under s. 7(c) of the Natural Gas Act, 15 U.S.C. s. 717f, or a natural gas transmission pipeline certified as an associated facility to an electrical power plant pursuant to the Florida Electrical Power Plant Siting Act, ss. 403.501-403.518, unless the applicant elects to apply for certification of that pipeline under ss. 403.9401-403.9425.

(c) Natural gas transmission pipelines that are owned or operated by a municipality or any agency thereof, by any person primarily for the local distribution of natural gas, or by a special district created by special act to distribute natural gas, unless the applicant elects to apply for certification of that pipeline under ss. 403.9401-403.9425.

CODING: Words ~~stricken~~ are deletions; words underlined are additions.

Section 19. Subsection (3) of section 720.3075, Florida Statutes, is amended to read:

720.3075 Prohibited clauses in association documents.—

(3) Homeowners' association documents, including declarations of covenants, articles of incorporation, or bylaws, may not preclude:

(a) The display of up to two portable, removable flags as described in s. 720.304(2)(a) by property owners. However, all flags must be displayed in a respectful manner consistent with the requirements for the United States flag under 36 U.S.C. chapter 10.

(b) Types or fuel sources of energy production which may be used, delivered, converted, or supplied by the following entities to serve customers within the association that such entities are authorized to serve:

1. A public utility or an electric utility as defined in s. 366.02;

2. An entity formed under s. 163.01 that generates, sells, or transmits electrical energy;

3. A natural gas utility as defined in s. 366.04(3)(c);

4. A natural gas transmission company as defined in s. 368.103; or

5. A Category I liquefied petroleum gas dealer, a Category II liquefied petroleum gas dispenser, or a Category III liquefied petroleum gas cylinder exchange operator as defined in s. 527.01.

(c) The use of an appliance, including a stove or grill, which uses the types or fuel sources of energy production which may be used, delivered, converted, or supplied by the entities listed in paragraph (b). As used in this paragraph, the term "appliance" means a device or apparatus manufactured and designed to use energy and for which the Florida Building Code or the Florida Fire Prevention Code provides specific requirements.

Section 20. (1) The Public Service Commission shall coordinate, develop, and recommend a plan under which an assessment of the security and resiliency of the state's electric grid and natural gas facilities against both physical threats and cyber threats may be conducted. In developing this plan, the commission shall consult with the Division of Emergency Management and, in its assessment of cyber threats, shall consult with the Florida Digital Service. All electric utilities, natural gas utilities, and natural gas pipelines operating in this state shall cooperate with the commission in developing the plan. The plan must address the manner in which information needed to conduct a security and resiliency assessment may be communicated, collected, shared, stored, and adequately protected from disclosure to avoid adverse impacts on the safe and reliable operation of the state's electric grid and natural gas facilities.

(2) By January 31, 2025, the commission shall submit its recommended plan to the Governor, the President of the Senate, and the Speaker of the House of Representatives. The plan must include any recommendations for legislation and may include other recommendations as determined by the commission.

Section 21. (1) Recognizing the evolution and advances that have occurred and continue to occur in nuclear power technologies, the Public Service Commission shall study and evaluate the technical and economic feasibility of using advanced nuclear power technologies, including small modular reactors, to meet the electrical power needs of the state, and research means to encourage and foster the installation and use of such technologies at military installations in the state in partnership with public utilities. In conducting this study, the commission shall consult with the Department of Environmental Protection and the Division of Emergency Management.

(2) By April 1, 2025, the commission shall prepare and submit a report to the Governor, the President of the Senate, and the Speaker of the House of Representatives, containing its findings and any recommendations for potential legislative or administrative actions that may enhance the use of advanced nuclear technologies in a manner consistent with the energy policy goals in s. 377.601(2), Florida Statutes.

Section 22. (1) Recognizing the continued development of technologies that support the use of hydrogen as a transportation fuel and the potential for such use to help meet the state's energy policy goals in s. 377.601(2), Florida Statutes, the Department of Transportation, in consultation with the Office of Energy within the Department of Agriculture and Consumer Services, shall study and evaluate the potential development of hydrogen fueling infrastructure, including fueling stations, to support hydrogen-powered vehicles that use the state highway system.

(2) By April 1, 2025, the Department of Transportation shall prepare and submit a report to the Governor, the President of the Senate, and the Speaker of the House of Representatives, containing its findings and any recommendations for potential legislative or administrative actions that may accommodate the future development of hydrogen fueling infrastructure in a manner consistent with the energy policy goals in s. 377.601(2), Florida Statutes.

Section 23. This act shall take effect July 1, 2024.

Approved by the Governor May 15, 2024.

Filed in Office Secretary of State May 15, 2024.

AN ACT

relating to the planning for, interconnection and operation of, and costs related to providing service for certain electrical loads and to the generation of electric power by a water supply or sewer service corporation.

BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF TEXAS:

SECTION 1. Section 35.004, Utilities Code, is amended by adding Subsections (c-1) and (c-2) to read as follows:

(c-1) The commission by rule shall ensure that a large load customer who is subject to the standards adopted under Section 37.0561 contributes to the recovery of the interconnecting electric utility's costs to interconnect the large load to the utility's system.

(c-2) An electric cooperative or municipally owned utility that has not adopted customer choice shall pass through to a large load customer who is subject to the standards adopted under Section 37.0561 the reasonable costs to interconnect the large load in a manner determined by the electric cooperative or municipally owned utility.

SECTION 2. Subchapter B, Chapter 37, Utilities Code, is amended by adding Section 37.0561 to read as follows:

Sec. 37.0561. PLANNING FOR AND INTERCONNECTION OF LARGE LOADS. (a) For the purposes of this section, a large load customer includes an entity requesting an interconnection that exceeds the demand threshold adopted under Subsection (c) and a successor in interest to such an entity.

(b) The commission by rule shall establish standards for interconnecting large load customers in the ERCOT power region in a manner designed to support business development in this state while minimizing the potential for stranded infrastructure costs and maintaining system reliability.

(c) The standards must apply only to customers requesting a new or expanded interconnection where the total load at a single site would exceed a demand threshold established by the commission based on the size of loads that significantly impact transmission needs in the ERCOT power region. The commission shall establish a demand threshold of 75 megawatts unless the commission determines that a lower threshold is necessary to accomplish the purposes described by Subsection (b).

(d) The standards must require each large load customer subject to Subsection (c) to disclose to the interconnecting electric utility or municipally owned utility whether the customer is pursuing a substantially similar request for electric service in this state the approval of which would result in the customer materially changing, delaying, or withdrawing the interconnection request. The disclosure may withhold or anonymize competitively sensitive details. The commission by rule shall prohibit an electric utility or municipally owned utility from selling, sharing, or disclosing information submitted to the utility under this subsection other than a disclosure to the commission or the independent organization certified under Section 39.151 for the

ERCOT power region, subject to appropriate confidentiality protections.

(e) The standards must require each interconnected large load customer subject to Subsection (c) to disclose to the interconnecting electric utility or municipally owned utility information about the customer's on-site backup generating facilities and require the interconnecting electric utility or municipally owned utility to provide the information to the independent organization certified under Section 39.151 for the ERCOT power region. For the purposes of this subsection, "on-site backup generating facilities" means generation that is not capable of exporting energy to the ERCOT transmission grid and that, in the aggregate, can serve at least 50 percent of on-site demand. The independent organization shall establish a threshold before or during an energy emergency alert at which the organization may issue reasonable notice that large load customers with on-site backup generating facilities may be directed to either deploy the customer's on-site backup generating facilities or curtail load. After the independent organization deploys all available market services, except for frequency responsive services, the independent organization may direct the applicable electric utility or municipally owned utility to require the large load customer to either deploy the customer's on-site backup generating facilities or curtail load. The independent organization shall include a deployment under this section as firm load shed when calculating any price adjustments for reliability deployments. This subsection does not:

(1) authorize or require a violation of any emissions limitation in state or federal law or a violation of any other environmental regulation; or

(2) prohibit a large load customer from participating in a service authorized by Section 39.170(b).

(f) The standards must set a flat study fee of at least $100,000 to be paid to the interconnecting electric utility or municipally owned utility for initial transmission screening studies for large loads subject to Subsection (c). A large load customer that requests additional capacity following the screening study must pay an additional study fee based on the new request. The interconnecting electric utility or municipally owned utility shall apply any unused portion of the initial transmission screening study fee as a credit toward satisfying financial obligations for procurement or interconnection agreements at the same geographic site.

(g) The standards must include a method for a large load customer subject to Subsection (c) to demonstrate site control for the proposed load location through an ownership interest, lease, or another legal interest acceptable to the commission.

(h) The standards must include uniform financial commitment requirements for the development of transmission infrastructure needed to serve a large load customer subject to Subsection (c). The standards must provide that satisfactory proof of financial commitment may include:

(1) security provided on a dollar per megawatt basis as set by the commission;

(2) contribution in aid of construction;

(3) security provided under an agreement that requires a large load customer to pay for significant equipment or services in advance of signing an agreement to establish electric delivery service; or

(4) a form of financial commitment acceptable to the commission other than those provided by Subdivisions (1)-(3).

(i) Security provided under Subsection (h)(1) must be refunded, in whole or in part, after the security is applied to any outstanding amounts owed:

(1) as the large load customer meets the customer's load ramp milestones and sustains operations for a prescribed period as determined by the commission;

(2) if the large load customer withdraws the customer's request for all or a portion of the requested capacity; or

(3) if capacity subject to a financial commitment will be reallocated to one or more other customers.

(j) The commission shall establish uniform requirements for determining when capacity that is subject to an outstanding financial commitment under this section may be reallocated.

(k) The standards must establish a procedure to allow the independent organization certified under Section 39.151 for the ERCOT power region to access any information collected by the interconnecting electric utility or municipally owned utility to ensure compliance with the standards for transmission planning analysis. Any customer-specific or competitively sensitive information obtained under this subsection is confidential and not subject to disclosure under Chapter 552, Government Code.

(l) The commission may not limit the authority of a municipally owned utility or an electric cooperative to impose electric service requirements for large load customers on their systems in addition to the standards adopted under this section.

(m) Notwithstanding the forecasted load growth and additional load currently seeking interconnection required to be considered under Section 37.056(c-1), the commission by rule shall establish criteria by which the independent organization certified under Section 39.151 for the ERCOT power region includes forecasted large load of any peak demand in the organization's transmission planning and resource adequacy models and reports.

SECTION 3. Section 39.002, Utilities Code, is amended to read as follows:

Sec. 39.002. APPLICABILITY. This chapter, other than Sections 39.151, 39.1516, 39.155, 39.157(e), 39.161, 39.162, 39.163, 39.169, 39.170, 39.203, 39.9051, 39.9052, and 39.914(e), and Subchapters M and N, does not apply to a municipally owned utility or an electric cooperative. Sections 39.157(e) and 39.203 apply only to a municipally owned utility or an electric cooperative that is offering customer choice. If there is a conflict between the specific provisions of this chapter and any other provisions of this title, except for Chapters 40 and 41, the provisions of this chapter control.

SECTION 4. Subchapter D, Chapter 39, Utilities Code, is amended by adding Sections 39.169 and 39.170 to read as follows:

Sec. 39.169. CO-LOCATION OF LARGE LOAD CUSTOMER WITH EXISTING GENERATION RESOURCE. (a) A power generation company, municipally owned utility, or electric cooperative must submit a notice to the independent organization certified under Section 39.151 for the ERCOT power region before implementing a net metering arrangement between an operating facility registered with the independent organization as a stand-alone generation resource as of September 1, 2025, and a new large load customer as described by Section 37.0561(c).

(b) This section does not apply to a generation resource:

(1) the registration for which included a co-located large load customer at the time of energization, regardless of whether the load was energized at a later date; or

(2) a majority interest of which is owned indirectly or directly as of January 1, 2025, by a parent company of the customer that participates in the new net metering arrangement.

(c) The electric cooperative, transmission and distribution utility, or municipally owned utility that provides electric service at the location of the new net metering arrangement may for reasonable cause including a violation of other law, object to the arrangement, provided however, that no reasonable cause objection may be raised after a final decision by the commission is issued under this section.

(d) The independent organization certified under Section 39.151 for the ERCOT power region shall study the system impacts of a proposed net metering arrangement and removal of generation for which the independent organization receives a notice under

Subsection (a) after the independent organization receives all information regarding the arrangement required by the independent organization to be submitted to the independent organization. The independent organization must complete the study and submit the results to the commission with any associated recommendations not later than the 120th day after the independent organization receives all required information regarding the arrangement. Not later than the 60th day after the date the commission receives the study results from the independent organization, the commission shall approve, deny, or impose reasonable conditions on the proposed net metering arrangement as necessary to maintain system reliability, including transmission security and resource adequacy impacts. The conditions must require a generation resource that makes dispatchable capacity available to the ERCOT power region before the implementation of a net metering arrangement under this section to make at least that amount of dispatchable capacity available to the ERCOT power region after the implementation of the arrangement at the direction of the independent organization in advance of an anticipated emergency condition. The conditions may include:

(1) requiring the retail customer who is served behind-the-meter to reduce load during certain events;

(2) requiring the generation resource to make capacity available to the ERCOT power region during certain events; or

(3) requiring customers to be held harmless for stranded or underutilized transmission assets resulting from the behind-the-meter operation.

(e) If the commission does not approve, deny, or impose reasonable conditions on a proposed net metering arrangement before the expiration of the deadline established by Subsection (d), the commission is considered to have approved the arrangement.

(f) If conditions imposed under Subsection (d) are not limited to a specific period, the commission shall review the conditions at least every five years to determine whether the conditions should be extended or rescinded.

(g) The parties to a proceeding under this section are limited to the commission, the independent organization certified under Section 39.151 for the ERCOT power region, the interconnecting electric cooperative, transmission and distribution utility, or municipally owned utility, and a party in the net metering arrangement.

(h) The commission shall post the decision made on each notice submitted under this section on the commission's Internet website. The commission may not post information regarding the decision that is competitively sensitive or otherwise considered confidential.

Sec. 39.170. LARGE LOAD DEMAND MANAGEMENT SERVICE. (a) The commission shall require the independent organization certified under Section 39.151 for the ERCOT power region to ensure that each electric cooperative, transmission and distribution utility, and municipally owned utility serving a transmission-voltage customer develops a protocol, including the installation of any necessary equipment or technology before the customer is interconnected, to allow the load to be curtailed during firm load shed. The electric cooperative, transmission and distribution utility, or municipally owned utility shall confer with the customer to the extent feasible to shed load in a coordinated manner. This subsection applies only to a load interconnected after December 31, 2025, that is not:

(1) load operated by a critical load industrial customer, as defined by Section 17.002; or

(2) designated as a critical natural gas facility under Section 38.074.

(b) The commission shall require the independent organization certified under Section 39.151 for the ERCOT power region to develop a reliability service to competitively procure demand reductions from large load customers with a demand of at least 75 megawatts to be deployed in the event of an anticipated emergency condition. The rules governing this service must:

(1) specify the periods when the service may be used to assist with maintaining reliability during extreme weather events;

(2) ensure that the independent organization provides at least a 24-hour notice to large load customers and requires each large load to remain curtailed for the duration of the energy emergency alert event or until the load can be recalled safely; and

(3) prohibit participation by any large load customer that curtails in response to the wholesale price of electricity, as determined by the independent organization certified under Section 39.151 for the ERCOT power region, or that otherwise participates in a different reliability or ancillary service.

(c) The independent organization certified under Section

39.151 for the ERCOT power region shall include a deployment under this section when calculating any price adjustments for reliability deployments.

SECTION 5. Subchapter A, Chapter 67, Water Code, is amended by adding Section 67.0115 to read as follows:

Sec. 67.0115. ELECTRIC GENERATION. (a) A corporation may generate electric power for use in the corporation's operations, limited to:

(1) powering water well pumps, service pumps, and other equipment for the production, treatment, and transportation of raw water; and

(2) powering infrastructure for the treatment and delivery of potable drinking water.

(b) For the purposes of Subsection (a), a corporation operating solely as a wholesale water supplier or sewer service in a county with a population of less than 350,000 may generate excess electric power in conjunction with the uses described in Subsection (a) for sale in the ERCOT power region to provide revenue for the corporation only if the corporation:

(1) primarily generates electric power solely for the uses described in Subsection (a); and

(2) registers as a power generation company under Section 39.351, Utilities Code.

(c) A corporation that generates electric power for sale under Subsection (b) shall account for and use the revenue from those sales in a manner that complies with Section 67.004. The revenue that accrues from those sales of electric power may be used by the corporation only for:

(1) the corporation's costs of producing and selling electric power, including administration, employees, equipment, fuel, and maintenance; or

(2) a purpose described by Section 67.002.

SECTION 6. (a) The Public Utility Commission of Texas shall evaluate whether the existing methodology used to charge wholesale transmission costs to distribution providers under Section 35.004(d), Utilities Code, continues to appropriately assign costs for transmission investment. The commission shall also evaluate:

(1) whether the current four coincident peak methodology used to calculate wholesale transmission rates ensures that all loads appropriately contribute to the recovery of an electric cooperative's, electric utility's, or municipally owned utility's costs to provide access to the transmission system;

(2) whether alternative methods to calculate wholesale transmission rates would more appropriately assign the cost of providing access to and wholesale service from the transmission system, such as consideration of multiple seasonal peak demands, demand during different length daily intervals, or peak energy intervals; and

(3) the portion of the costs related to access to and wholesale service from the transmission system that should be nonbypassable, consistent with Section 35.004(c-1), Utilities Code, as added by this Act.

(b) The Public Utility Commission of Texas shall evaluate whether the commission's retail ratemaking practices ensure that transmission cost recovery appropriately charges the system costs that are caused by each customer class.

(c) The Public Utility Commission of Texas shall begin the evaluation required under Subsection (a) of this section not later than the 90th day after the effective date of this Act. After completion of the evaluation project and not later than December 31, 2026, the commission shall amend commission rules to ensure that wholesale transmission charges appropriately assign costs for transmission investment.

SECTION 7. Section 35.004(c-1), Utilities Code, as added by this Act, applies only to an interconnection agreement entered into on or after the effective date of this Act.

SECTION 8. This Act takes effect immediately if it receives a vote of two-thirds of all the members elected to each house, as provided by Section 39, Article III, Texas Constitution. If this Act does not receive the vote necessary for immediate effect, this Act takes effect September 1, 2025.

President of the Senate | Speaker of the House

I hereby certify that S.B. No. 6 passed the Senate on March 19, 2025, by the following vote: Yeas 31, Nays 0; and that the Senate concurred in House amendments on May 29, 2025, by the following vote: Yeas 31, Nays 0.

Secretary of the Senate

I hereby certify that S.B. No. 6 passed the House, with amendments, on May 27, 2025, by the following vote: Yeas 103, Nays 25, two present not voting.

Chief Clerk of the House

Approved:

Date

Governor

Presidential Documents

Executive Order 14154 of January 20, 2025

Unleashing American Energy

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Background.* America is blessed with an abundance of energy and natural resources that have historically powered our Nation's economic prosperity. In recent years, burdensome and ideologically motivated regulations have impeded the development of these resources, limited the generation of reliable and affordable electricity, reduced job creation, and inflicted high energy costs upon our citizens. These high energy costs devastate American consumers by driving up the cost of transportation, heating, utilities, farming, and manufacturing, while weakening our national security.

It is thus in the national interest to unleash America's affordable and reliable energy and natural resources. This will restore American prosperity—including for those men and women who have been forgotten by our economy in recent years. It will also rebuild our Nation's economic and military security, which will deliver peace through strength.

Sec. 2. *Policy.* It is the policy of the United States:

(a) to encourage energy exploration and production on Federal lands and waters, including on the Outer Continental Shelf, in order to meet the needs of our citizens and solidify the United States as a global energy leader long into the future;

(b) to establish our position as the leading producer and processor of non-fuel minerals, including rare earth minerals, which will create jobs and prosperity at home, strengthen supply chains for the United States and its allies, and reduce the global influence of malign and adversarial states;

(c) to protect the United States's economic and national security and military preparedness by ensuring that an abundant supply of reliable energy is readily accessible in every State and territory of the Nation;

(d) to ensure that all regulatory requirements related to energy are grounded in clearly applicable law;

(e) to eliminate the "electric vehicle (EV) mandate" and promote true consumer choice, which is essential for economic growth and innovation, by removing regulatory barriers to motor vehicle access; by ensuring a level regulatory playing field for consumer choice in vehicles; by terminating, where appropriate, state emissions waivers that function to limit sales of gasoline-powered automobiles; and by considering the elimination of unfair subsidies and other ill-conceived government-imposed market distortions that favor EVs over other technologies and effectively mandate their purchase by individuals, private businesses, and government entities alike by rendering other types of vehicles unaffordable;

(f) to safeguard the American people's freedom to choose from a variety of goods and appliances, including but not limited to lightbulbs, dishwashers, washing machines, gas stoves, water heaters, toilets, and shower heads, and to promote market competition and innovation within the manufacturing and appliance industries;

(g) to ensure that the global effects of a rule, regulation, or action shall, whenever evaluated, be reported separately from its domestic costs and benefits, in order to promote sound regulatory decision making and prioritize the interests of the American people;

(h) to guarantee that all executive departments and agencies (agencies) provide opportunity for public comment and rigorous, peer-reviewed scientific analysis; and

(i) to ensure that no Federal funding be employed in a manner contrary to the principles outlined in this section, unless required by law.

Sec. 3. *Immediate Review of All Agency Actions that Potentially Burden the Development of Domestic Energy Resources*. (a) The heads of all agencies shall review all existing regulations, orders, guidance documents, policies, settlements, consent orders, and any other agency actions (collectively, agency actions) to identify those agency actions that impose an undue burden on the identification, development, or use of domestic energy resources—with particular attention to oil, natural gas, coal, hydropower, biofuels, critical mineral, and nuclear energy resources—or that are otherwise inconsistent with the policy set forth in section 2 of this order, including restrictions on consumer choice of vehicles and appliances.

(b) Within 30 days of the date of this order, the head of each agency shall, in consultation with the director of the Office of Management and Budget (OMB) and the National Economic Council (NEC), develop and begin implementing action plans to suspend, revise, or rescind all agency actions identified as unduly burdensome under subsection (a) of this section, as expeditiously as possible and consistent with applicable law. The head of any agency who determines that such agency does not have agency actions described in subsection (a) of this section shall submit to the Director of OMB a written statement to that effect and, absent a determination by the Director of OMB that such agency does have agency actions described in this subsection, shall have no further responsibilities under this section.

(c) Agencies shall promptly notify the Attorney General of any steps taken pursuant to subsection (a) of this section so that the Attorney General may, as appropriate:

(i) provide notice of this Executive Order and any such actions to any court with jurisdiction over pending litigation in which such actions may be relevant; and

(ii) request that such court stay or otherwise delay further litigation, or seek other appropriate relief consistent with this order, pending the completion of the administrative actions described in this order.

(d) Pursuant to the policy outlined in section 2 of this order, the Attorney General shall consider whether pending litigation against illegal, dangerous, or harmful policies should be resolved through stays or other relief.

Sec. 4. *Revocation of and Revisions to Certain Presidential and Regulatory Actions*. (a) The following are revoked and any offices established therein are abolished:

(i) Executive Order 13990 of January 20, 2021 (Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis);

(ii) Executive Order 13992 of January 20, 2021 (Revocation of Certain Executive Orders Concerning Federal Regulation);

(iii) Executive Order 14008 of January 27, 2021 (Tackling the Climate Crisis at Home and Abroad);

(iv) Executive Order 14007 of January 27, 2021 (President's Council of Advisors on Science and Technology);

(v) Executive Order 14013 of February 4, 2021 (Rebuilding and Enhancing Programs to Resettle Refugees and Planning for the Impact of Climate Change on Migration);

(vi) Executive Order 14027 of May 7, 2021 (Establishment of the Climate Change Support Office);

(vii) Executive Order 14030 of May 20, 2021 (Climate-Related Financial Risk);

(viii) Executive Order 14037 of August 5, 2021 (Strengthening American Leadership in Clean Cars and Trucks);

(ix) Executive Order 14057 of December 8, 2021 (Catalyzing Clean Energy Industries and Jobs Through Federal Sustainability);

(x) Executive Order 14072 of April 22, 2022 (Strengthening the Nation's Forests, Communities, and Local Economies);

(xi) Executive Order 14082 of September 12, 2022 (Implementation of the Energy and Infrastructure Provisions of the Inflation Reduction Act of 2022); and

(xii) Executive Order 14096 of April 21, 2023 (Revitalizing Our Nation's Commitment to Environmental Justice for All).

(b) All activities, programs, and operations associated with the American Climate Corps, including actions taken by any agency shall be terminated immediately. Within one day of the date of this order, the Secretary of the Interior shall submit a letter to all parties to the "American Climate Corps Memorandum of Understanding" dated December 2023 to terminate the memorandum, and the head of each party to the memorandum shall agree to the termination in writing.

(c) Any assets, funds, or resources allocated to an entity or program abolished by subsection (a) of this section shall be redirected or disposed of in accordance with applicable law.

(d) The head of any agency that has taken action respecting offices and programs in subsection (a) shall take all necessary steps to ensure that all such actions are terminated or, if necessary, appropriate, or required by law, that such activities are transitioned to other agencies or entities.

(e) Any contract or agreement between the United States and any third party on behalf of the entities or programs abolished in subsection (a) of this section, or in furtherance of them, shall be terminated for convenience, or otherwise, as quickly as permissible under the law.

Sec. 5. *Unleashing Energy Dominance through Efficient Permitting*. (a) Executive Order 11991 of May 24, 1977 (Relating to protection and enhancement of environmental quality) is hereby revoked.

(b) To expedite and simplify the permitting process, within 30 days of the date of this order, the Chairman of the Council on Environmental Quality (CEQ) shall provide guidance on implementing the National Environmental Policy Act (NEPA), 42 U.S.C. 4321 *et seq.*, and propose rescinding CEQ's NEPA regulations found at 40 CFR 1500 *et seq*.

(c) Following the provision of the guidance, the Chairman of CEQ shall convene a working group to coordinate the revision of agency-level implementing regulations for consistency. The guidance in subsection (b) and any resulting implementing regulations must expedite permitting approvals and meet deadlines established in the Fiscal Responsibility Act of 2023 (Public Law 118–5). Consistent with applicable law, all agencies must prioritize efficiency and certainty over any other objectives, including those of activist groups, that do not align with the policy goals set forth in section 2 of this order or that could otherwise add delays and ambiguity to the permitting process.

(d) The Secretaries of Defense, Interior, Agriculture, Commerce, Housing and Urban Development, Transportation, Energy, Homeland Security, the Administrator of the Environmental Protection Agency (EPA), the Chairman of CEQ, and the heads of any other relevant agencies shall undertake all available efforts to eliminate all delays within their respective permitting processes, including through, but not limited to, the use of general permitting and permit by rule. For any project an agency head deems essential for the Nation's economy or national security, agencies shall use all possible authorities, including emergency authorities, to expedite the adjudication of Federal permits. Agencies shall work closely with project sponsors to realize the ultimate construction or development of permitted projects.

(e) The Director of the NEC and the Director of the Office of Legislative Affairs shall jointly prepare recommendations to Congress, which shall:

(i) facilitate the permitting and construction of interstate energy transportation and other critical energy infrastructure, including, but not limited to, pipelines, particularly in regions of the Nation that have lacked such development in recent years; and

(ii) provide greater certainty in the Federal permitting process, including, but not limited to, streamlining the judicial review of the application of NEPA.

Sec. 6. *Prioritizing Accuracy in Environmental Analyses.* (a) In all Federal permitting adjudications or regulatory processes, all agencies shall adhere to only the relevant legislated requirements for environmental considerations and any considerations beyond these requirements are eliminated. In fulfilling all such requirements, agencies shall strictly use the most robust methodologies of assessment at their disposal and shall not use methodologies that are arbitrary or ideologically motivated.

(b) The Interagency Working Group on the Social Cost of Greenhouse Gases (IWG), which was established pursuant to Executive Order 13990, is hereby disbanded, and any guidance, instruction, recommendation, or document issued by the IWG is withdrawn as no longer representative of governmental policy including:

(i) the Presidential Memorandum of January 27, 2021 (Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking);

(ii) the Report of the Greenhouse Gas Monitoring and Measurement Interagency Working Group of November 2023 (National Strategy to Advance an Integrated U.S. Greenhouse Gas Measurement, Monitoring, and Information System);

(iii) the Technical Support Document of February 2021 (Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990); and

(iv) estimates of the social cost of greenhouse gases, including the estimates for the social cost of carbon, the social cost of methane, or the social cost of nitrous oxide based, in whole or in part, on the IWG's work or guidance.

(c) The calculation of the ''social cost of carbon'' is marked by logical deficiencies, a poor basis in empirical science, politicization, and the absence of a foundation in legislation. Its abuse arbitrarily slows regulatory decisions and, by rendering the United States economy internationally uncompetitive, encourages a greater human impact on the environment by affording less efficient foreign energy producers a greater share of the global energy and natural resource market. Consequently, within 60 days of the date of this order, the Administrator of the EPA shall issue guidance to address these harmful and detrimental inadequacies, including consideration of eliminating the ''social cost of carbon'' calculation from any Federal permitting or regulatory decision.

(d) Prior to the guidance issued pursuant to subsection (c) of this section, agencies shall ensure estimates to assess the value of changes in greenhouse gas emissions resulting from agency actions, including with respect to the consideration of domestic versus international effects and evaluating appropriate discount rates, are, to the extent permitted by law, consistent with the guidance contained in OMB Circular A–4 of September 17, 2003 (Regulatory Analysis).

(e) Furthermore, the head of each agency shall, as appropriate and consistent with applicable law, initiate a process to make such changes to any rule, regulation, policy or action as may be necessary to ensure consistency with the Regulatory Analysis.

(f) Within 30 days of the date of this order, the Administrator of the EPA, in collaboration with the heads of any other relevant agencies, shall submit joint recommendations to the Director of OMB on the legality and continuing applicability of the Administrator's findings, ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' Final Rule, 74 FR 66496 (December 15, 2009).

Sec. 7. *Terminating the Green New Deal.* (a) All agencies shall immediately pause the disbursement of funds appropriated through the Inflation Reduction Act of 2022 (Public Law 117–169) or the Infrastructure Investment and Jobs Act (Public Law 117–58), including but not limited to funds for electric vehicle charging stations made available through the National Electric Vehicle Infrastructure Formula Program and the Charging and Fueling Infrastructure Discretionary Grant Program, and shall review their processes, policies, and programs for issuing grants, loans, contracts, or any other financial disbursements of such appropriated funds for consistency with the law and the policy outlined in section 2 of this order. Within 90 days of the date of this order, all agency heads shall submit a report to the Director of the NEC and Director of OMB that details the findings of this review, including recommendations to enhance their alignment with the policy set forth in section 2. No funds identified in this subsection (a) shall be disbursed by a given agency until the Director of OMB and Assistant to the President for Economic Policy have determined that such disbursements are consistent with any review recommendations they have chosen to adopt.

(b) When procuring goods and services, making decisions about leases, and making other arrangements that result in disbursements of Federal funds, agencies shall prioritize cost-effectiveness, American workers and businesses, and the sensible use of taxpayer money, to the greatest extent. The Director of OMB shall finalize and circulate guidelines to further implement this subsection.

(c) All agencies shall assess whether enforcement discretion of authorities and regulations can be utilized to advance the policy outlined in section 2 of this order. Within 30 days of the date of this order, each agency shall submit a report to the Director of OMB identifying any such instances.

Sec. 8. *Protecting America's National Security.* (a) The Secretary of Energy is directed restart reviews of applications for approvals of liquified natural gas export projects as expeditiously as possible, consistent with applicable law. In assessing the ''Public Interest'' to be advanced by any particular application, the Secretary of Energy shall consider the economic and employment impacts to the United States and the impact to the security of allies and partners that would result from granting the application.

(b) With respect to any proposed deepwater port for the export of liquefied natural gas (project) for which a favorable record of decision (ROD) has previously been issued pursuant to the Deepwater Port Act of 1974 (DWPA), 33 U.S.C. 1501 *et seq.,* the Administrator of the Maritime Administration (MARAD) shall, within 30 days of the date of this order and consistent with applicable law, determine whether any refinements to the project proposed subsequent to the ROD are likely to result in adverse environmental consequences that substantially differ from those associated with the originally-evaluated project so as to present a seriously different picture of the foreseeable adverse environmental consequences (seriously different consequences). In making this determination, MARAD shall qualitatively assess any difference in adverse environmental consequences between the project with and without the proposed refinements, including any potential consequences not addressed in the final Environmental Impact Statement (EIS), which shall be considered adequate under NEPA notwithstanding any revisions to NEPA that may have been enacted following the final EIS. MARAD shall submit this determination, together with a detailed justification, to the Secretary of Transportation and to the President.

(c) Pursuant to subsection (b) of this section, if MARAD determines that such refinements are not likely to result in seriously different consequences, it shall include in that determination a description of the refinements to supplement and update the ROD, if necessary and then no later than 30 additional days, he shall issue a DWPA license.

(d) If MARAD determines, with concurrence from the Secretary of Transportation, that such proposed refinements are likely to result in seriously different consequences, it shall, within 60 days after submitting such determination, issue an Environmental Assessment (EA) examining such consequences and, with respect to all other environmental consequences not changed due to project refinements, shall reaffirm the conclusions of the final EIS. Within 30 days after issuing the EA, MARAD shall issue an addendum to the ROD, if necessary, and shall, within 30 additional days, issue a DWPA license consistent with the ROD.

Sec. 9. *Restoring America's Mineral Dominance*. (a) The Secretary of the Interior, Secretary of Agriculture, Administrator of the EPA, Chairman of CEQ, and the heads of any other relevant agencies, as appropriate, shall identify all agency actions that impose undue burdens on the domestic mining and processing of non-fuel minerals and undertake steps to revise or rescind such actions.

(b) The Secretaries of the Interior and Agriculture shall reassess any public lands withdrawals for potential revision.

(c) The Secretary of the Interior shall instruct the Director of the U.S. Geological Survey to consider updating the Survey's list of critical minerals, including for the potential of including uranium.

(d) The Secretary of the Interior shall prioritize efforts to accelerate the ongoing, detailed geologic mapping of the United States, with a focus on locating previously unknown deposits of critical minerals.

(e) The Secretary of Energy shall ensure that critical mineral projects, including the processing of critical minerals, receive consideration for Federal support, contingent on the availability of appropriated funds.

(f) The United States Trade Representative shall assess whether exploitative practices and state-assisted mineral projects abroad are unlawful or unduly burden or restrict United States commerce.

(g) The Secretary of Commerce shall assess the national security implications of the Nation's mineral reliance and the potential for trade action.

(h) The Secretary of Homeland Security shall assess the quantity and inflow of minerals that are likely the product of forced labor into the United States and whether such inflows pose a threat to national security and, within 90 days of the date of this order, shall provide this assessment to the Director of the NEC.

(i) The Secretary of Defense shall consider the needs of the United States in supplying and maintaining the National Defense Stockpile, review the legal authorities and obligations in managing the National Defense Stockpile, and take all appropriate steps to ensure that the National Defense Stockpile will provide a robust supply of critical minerals in event of future shortfall.

(j) Within 60 days of the date of this order, the Secretary of State, Secretary of Commerce, Secretary of Labor, the United States Trade Representative, and the heads of any other relevant agencies, shall submit a report to the Assistant to the President for Economic Policy that includes policy recommendations to enhance the competitiveness of American mining and refining companies in other mineral-wealthy nations.

(k) The Secretary of State shall consider opportunities to advance the mining and processing of minerals within the United States through the Quadrilateral Security Dialogue.

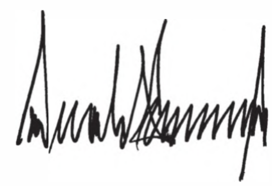
Sec. 10. *General Provisions*. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented in a manner consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
January 20, 2025.

[FR Doc. 2025–01956
Filed 1–28–25; 8:45 am]
Billing code 3395–F4–P

Federal Register
Vol. 90, No. 18
Wednesday, January 29, 2025

Presidential Documents

Title 3—

The President

Executive Order 14156 of January 20, 2025

Declaring a National Energy Emergency

By the authority vested in me as President by the Constitution and the laws of the United States of America, including the National Emergencies Act (50 U.S.C. 1601 *et seq.*) ("NEA"), and section 301 of title 3, United States Code, it is hereby ordered:

Section 1. *Purpose.* The energy and critical minerals ("energy") identification, leasing, development, production, transportation, refining, and generation capacity of the United States are all far too inadequate to meet our Nation's needs. We need a reliable, diversified, and affordable supply of energy to drive our Nation's manufacturing, transportation, agriculture, and defense industries, and to sustain the basics of modern life and military preparedness. Caused by the harmful and shortsighted policies of the previous administration, our Nation's inadequate energy supply and infrastructure causes and makes worse the high energy prices that devastate Americans, particularly those living on low- and fixed-incomes.

This active threat to the American people from high energy prices is exacerbated by our Nation's diminished capacity to insulate itself from hostile foreign actors. Energy security is an increasingly crucial theater of global competition. In an effort to harm the American people, hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets. An affordable and reliable domestic supply of energy is a fundamental requirement for the national and economic security of any nation.

The integrity and expansion of our Nation's energy infrastructure—from coast to coast—is an immediate and pressing priority for the protection of the United States' national and economic security. It is imperative that the Federal government puts the physical and economic wellbeing of the American people first.

Moreover, the United States has the potential to use its unrealized energy resources domestically, and to sell to international allies and partners a reliable, diversified, and affordable supply of energy. This would create jobs and economic prosperity for Americans forgotten in the present economy, improve the United States' trade balance, help our country compete with hostile foreign powers, strengthen relations with allies and partners, and support international peace and security. Accordingly, our Nation's dangerous energy situation inflicts unnecessary and perilous constraints on our foreign policy.

The policies of the previous administration have driven our Nation into a national emergency, where a precariously inadequate and intermittent energy supply, and an increasingly unreliable grid, require swift and decisive action. Without immediate remedy, this situation will dramatically deteriorate in the near future due to a high demand for energy and natural resources to power the next generation of technology. The United States' ability to remain at the forefront of technological innovation depends on a reliable supply of energy and the integrity of our Nation's electrical grid. Our Nation's current inadequate development of domestic energy resources leaves us vulnerable to hostile foreign actors and poses an imminent and growing threat to the United States' prosperity and national security.

These numerous problems are most pronounced in our Nation's Northeast and West Coast, where dangerous State and local policies jeopardize our Nation's core national defense and security needs, and devastate the prosperity of not only local residents but the entire United States population. The United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy. In light of these findings, I hereby declare a national emergency.

Sec. 2. *Emergency Approvals*. (a) The heads of executive departments and agencies (''agencies'') shall identify and exercise any lawful emergency authorities available to them, as well as all other lawful authorities they may possess, to facilitate the identification, leasing, siting, production, transportation, refining, and generation of domestic energy resources, including, but not limited to, on Federal lands. If an agency assesses that use of either Federal eminent domain authorities or authorities afforded under the Defense Production Act (Public Law 81–774, 50 U.S.C. 4501 *et seq.*) are necessary to achieve this objective, the agency shall submit recommendations for a course of action to the President, through the Assistant to the President for National Security Affairs.

(b) Consistent with 42 U.S.C. 7545(c)(4)(C)(ii)(III), the Administrator of the Environmental Protection Agency, after consultation with, and concurrence by, the Secretary of Energy, shall consider issuing emergency fuel waivers to allow the year-round sale of E15 gasoline to meet any projected temporary shortfalls in the supply of gasoline across the Nation.

Sec. 3. *Expediting the Delivery cf Energy Infrastructure*. (a) To facilitate the Nation's energy supply, agencies shall identify and use all relevant lawful emergency and other authorities available to them to expedite the completion of all authorized and appropriated infrastructure, energy, environmental, and natural resources projects that are within the identified authority of each of the Secretaries to perform or to advance.

(b) To protect the collective national and economic security of the United States, agencies shall identify and use all lawful emergency or other authorities available to them to facilitate the supply, refining, and transportation of energy in and through the West Coast of the United States, Northeast of the United States, and Alaska.

(c) The Secretaries shall provide such reports regarding activities under this section as may be requested by the Assistant to the President for Economic Policy.

Sec. 4. *Emergency Regulations and Nationwide Permits Under the Clean Water Act (CWA) and Other Statutes Administered by the Army Corps cf Engineers*. (a) Within 30 days from the date of this order, the heads of all agencies, as well as the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to emergency treatment pursuant to the regulations and nationwide permits promulgated by the Corps, or jointly by the Corps and EPA, pursuant to section 404 of the Clean Water Act, 33 U.S.C. 1344, section 10 of the Rivers and Harbors Act of March 3, 1899, 33 U.S.C. 403, and section 103 of the Marine Protection Research and Sanctuaries Act of 1972, 33 U.S.C. 1413 (collectively, the ''emergency Army Corps permitting provisions''); and

(ii) shall provide a summary report, listing such actions, to the Director of the Office of Management and Budget (''OMB''); the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Assistant to the President for Economic Policy; and the Chairman of the Council on Environmental Quality (CEQ). Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the fullest extent possible and consistent with applicable law, the emergency Army Corps permitting provisions to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, each department and agency shall provide a status report to the OMB Director; the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works; the Director of the National Economic Council; and the Chairman of the CEQ. Each such report shall list actions taken within subsection (a)(i) of this section, shall list the status of any previously reported planned or potential actions, and shall list any new planned or potential actions that fall within subsection (a)(i). Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order.

(d) The Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, shall be available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the emergency Army Corps permitting provisions. The Administrator of the EPA shall provide prompt cooperation to the Secretary of the Army and to agencies in connection with the discharge of the responsibilities described in this section.

Sec. 5. *Endangered Species Act (ESA) Emergency Consultation Regulations.* (a) No later than 30 days from the date of this order, the heads of all agencies tasked in this order shall:

(i) identify planned or potential actions to facilitate the Nation's energy supply that may be subject to the regulation on consultations in emergencies, 50 CFR 402.05, promulgated by the Secretary of the Interior and the Secretary of Commerce pursuant to the Endangered Species Act (''ESA''), 16 U.S.C. 1531 *et seq.;* and

(ii) provide a summary report, listing such actions, to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Such report may be combined, as appropriate, with any other reports required by this order.

(b) Agencies are directed to use, to the maximum extent permissible under applicable law, the ESA regulation on consultations in emergencies, to facilitate the Nation's energy supply.

(c) Within 30 days following the submission of the initial summary report described in subsection (a)(ii) of this section, the head of each agency shall provide a status report to the Secretary of the Interior, the Secretary of Commerce, the OMB Director, the Director of the National Economic Council, and the Chairman of CEQ. Each such report shall list actions taken within the categories described in subsection (a)(i) of this section, the status of any previously reported planned or potential actions, and any new planned or potential actions within these categories. Such status reports shall thereafter be provided to these officials at least every 30 days for the duration of the national emergency and may be combined, as appropriate, with any other reports required by this order. The OMB Director may grant discretionary exemptions from this reporting requirement.

(d) The Secretary of the Interior shall ensure that the Director of the Fish and Wildlife Service, or the Director's authorized representative, is available to consult promptly with agencies and to take other prompt and appropriate action concerning the application of the ESA's emergency regulations. The Secretary of Commerce shall ensure that the Assistant Administrator for Fisheries for the National Marine Fisheries Service, or the Assistant Administrator's authorized representative, is available for such consultation and to take such other action.

Sec. 6. *Convening the Endangered Species Act Committee.* (a) In acting as Chairman of the Endangered Species Act Committee, the Secretary of the Interior shall convene the Endangered Species Act Committee not less than quarterly, unless otherwise required by law, to review and consider any lawful applications submitted by an agency, the Governor of a State, or any applicant for a permit or license who submits for exemption from obligations imposed by Section 7 of the ESA.

(b) To the extent practicable under the law, the Secretary of the Interior shall ensure a prompt and efficient review of all submissions described in subsection (a) of this section, to include identification of any legal deficiencies, in order to ensure an initial determination within 20 days of receipt and the ability to convene the Endangered Species Act Committee to resolve the submission within 140 days of such initial determination of eligibility.

(c) In the event that the committee has no pending applications for review, the committee or its designees shall nonetheless convene to identify obstacles to domestic energy infrastructure specifically deriving from implementation of the ESA or the Marine Mammal Protection Act, to include regulatory reform efforts, species listings, and other related matters with the aim of developing procedural, regulatory, and interagency improvements.

Sec. 7. *Coordinated Infrastructure Assistance*. (a) In collaboration with the Secretaries of Interior and Energy, the Secretary of Defense shall conduct an assessment of the Department of Defense's ability to acquire and transport the energy, electricity, or fuels needed to protect the homeland and to conduct operations abroad, and, within 60 days, shall submit this assessment to the Assistant to the President for National Security Affairs. This assessment shall identify specific vulnerabilities, including, but not limited to, potentially insufficient transportation and refining infrastructure across the Nation, with a focus on such vulnerabilities within the Northeast and West Coast regions of the United States. The assessment shall also identify and recommend the requisite authorities and resources to remedy such vulnerabilities, consistent with applicable law.

(b) In accordance with section 301 of the National Emergencies Act (50 U.S.C. 1631), the construction authority provided in section 2808 of title 10, United States Code, is invoked and made available, according to its terms, to the Secretary of the Army, acting through the Assistant Secretary of the Army for Civil Works, to address any vulnerabilities identified in the assessment mandated by subsection (a). Any such recommended actions shall be submitted to the President for review, through the Assistant to the President for National Security Affairs and the Assistant to the President for Economic Policy.

Sec. 8. *Definitions*. For purposes of this order, the following definitions shall apply:

(a) The term "energy" or "energy resources" means crude oil, natural gas, lease condensates, natural gas liquids, refined petroleum products, uranium, coal, biofuels, geothermal heat, the kinetic movement of flowing water, and critical minerals, as defined by 30 U.S.C. 1606 (a)(3).

(b) The term "production" means the extraction or creation of energy.

(c) The term "transportation" means the physical movement of energy, including through, but not limited to, pipelines.

(d) The term "refining" means the physical or chemical change of energy into a form that can be used by consumers or users, including, but not limited to, the creation of gasoline, diesel, ethanol, aviation fuel, or the beneficiation, enrichment, or purification of minerals.

(e) The term "generation" means the use of energy to produce electricity or thermal power and the transmission of electricity from its site of generation.

(f) The term "energy supply" means the production, transportation, refining, and generation of energy.

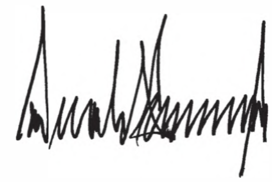
Sec. 9. *General Provisions*. (a) Nothing in this order shall be construed to impair or otherwise affect:

(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of OMB relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



THE WHITE HOUSE,
January 20, 2025.

[FR Doc. 2025–02003
Filed 1–28–25; 11:15 am]
Billing code 3395–F4–P

Federal Register
Vol. 90, No. 130
Thursday, July 10, 2025

Presidential Documents

Title 3—

The President

Executive Order 14315 of July 7, 2025

Ending Market Distorting Subsidies for Unreliable, Foreign-Controlled Energy Sources

By the authority vested in me as President by the Constitution and the laws of the United States of America, it is hereby ordered:

Section 1. *Purpose*. For too long, the Federal Government has forced American taxpayers to subsidize expensive and unreliable energy sources like wind and solar. The proliferation of these projects displaces affordable, reliable, dispatchable domestic energy sources, compromises our electric grid, and denigrates the beauty of our Nation's natural landscape. Moreover, reliance on so-called "green" subsidies threatens national security by making the United States dependent on supply chains controlled by foreign adversaries. Ending the massive cost of taxpayer handouts to unreliable energy sources is vital to energy dominance, national security, economic growth, and the fiscal health of the Nation.

Sec. 2. *Policy*. It is the policy of the United States to:

(a) rapidly eliminate the market distortions and costs imposed on taxpayers by so-called "green" energy subsidies;

(b) build upon and strengthen the repeal of, and modifications to, wind, solar, and other "green" energy tax credits in the One Big Beautiful Bill Act; and

(c) end taxpayer support for unaffordable and unreliable "green" energy sources and supply chains built in, and controlled by, foreign adversaries.

Sec. 3. *Tax Credits and One Big Beautiful Bill Act Implementation by the Department of the Treasury*. (a) Within 45 days following enactment of the One Big Beautiful Bill Act, the Secretary of the Treasury shall take all action as the Secretary of the Treasury deems necessary and appropriate to strictly enforce the termination of the clean electricity production and investment tax credits under sections 45Y and 48E of the Internal Revenue Code for wind and solar facilities. This includes issuing new and revised guidance as the Secretary of the Treasury deems appropriate and consistent with applicable law to ensure that policies concerning the "beginning of construction" are not circumvented, including by preventing the artificial acceleration or manipulation of eligibility and by restricting the use of broad safe harbors unless a substantial portion of a subject facility has been built.

(b) Within 45 days following enactment of the One Big Beautiful Bill Act, the Secretary of the Treasury shall take prompt action as the Secretary of the Treasury deems appropriate and consistent with applicable law to implement the enhanced Foreign Entity of Concern restrictions in the One Big Beautiful Bill Act.

Sec. 4. *One Big Beautiful Bill Act Implementation by the Department of the Interior*. (a) Within 45 days following enactment of the One Big Beautiful Bill Act, the Secretary of the Interior shall conduct a review of regulations, guidance, policies, and practices under the Department of the Interior's jurisdiction to determine whether any provide preferential treatment to wind and solar facilities in comparison to dispatchable energy sources. The Secretary of the Interior shall then revise any identified regulations, guidance, policies, and practices as appropriate and consistent with applicable law to eliminate any such preferences for wind and solar facilities.

Sec. 5. *Reports*. Within 45 days of the date of this order, the Secretary of the Treasury and the Secretary of the Interior shall submit a report to the President, through the Assistant to the President for Economic Policy, the findings made under, and actions taken and planned to be taken to implement, this order.

Sec. 6. *General Provisions*. (a) Nothing in this order shall be construed to impair or otherwise affect:

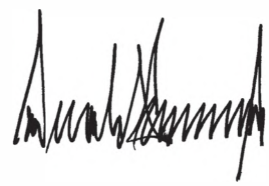
(i) the authority granted by law to an executive department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.

(d) The costs for publication of this order shall be borne by the Department of the Treasury.



THE WHITE HOUSE,
July 7, 2025.

[FR Doc. 2025–12961
Filed 7–9–25; 11:15 am]
Billing code 4810–25–P

Exhibit G

Placeholder

for

United States Treasury Guidance Relating to the
"One Big, Beautiful Bill Act"

RON DESANTIS
GOVERNOR

June 27, 2025

Secretary Cord Byrd
Secretary of State
R.A. Gray Building
500 South Bronough Street
Tallahassee, Florida 32399

Dear Secretary Byrd:

By the authority vested in me as Governor of the State of Florida, under the provisions of Article III, Section 8 of the Florida Constitution, I do hereby veto and transmit my objection to Committee Substitute for Committee Substitute for Senate Bill 1574 (CS/CS/SB 1574), enacted during the 127th Session of the Legislature of Florida during the Regular Session of 2025 and entitled:

An act relating to Energy Infrastructure Investment

CS/CS/SB 1574 requires the Public Service Commission (PSC) to create a new experimental rate mechanism to permit utilities to bill ratepayers for capital investments in renewable natural gas. The bill also includes a provision requiring the PSC to consider green energy credits when establishing and reviewing utility rate requests that are inconsistent with state energy policy.

For this reason, I withhold my approval of SB 1574 and do hereby veto the same.

Sincerely,

Ron DeSantis
Governor

Vinson&Elkins

Jeffrey M. Jakubiak jjakubiak@velaw.com
Tel +1.212.237.0082 **Fax** +1.917.720.9115

CONTAINS REQUEST FOR PRIVILEGED TREATMENT

June 10, 2025

Debbie-Anne A. Reese, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Re: *Vandolah Power Company L.L.C. and Florida Power & Light Company*
Docket No. EC25-___-000
Application Pursuant to Federal Power Act Section 203

Dear Secretary Reese:

Enclosed, please find the Application for Approval Pursuant to Section 203 of the Federal Power Act by Vandolah Power Company L.L.C. and Florida Power & Light Company ("Applicants"). As noted therein, Applicants respectfully request: (i) a 30-day notice period and (ii) an order approving the subject transaction by December 8, 2025.

Thank you for your assistance in this matter. Please contact the undersigned with any questions.

Yours truly,

/s/ Jeffrey M. Jakubiak

Jeffrey M. Jakubiak
Ankush J. Joshi

Attorneys for Florida Power & Light Company
on Behalf of Applicants

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.	)	Docket No. EC25-___-000
Florida Power & Light Company	)	

APPLICATION PURSUANT TO SECTION 203 OF THE FEDERAL POWER ACT

Mark C. Williams
Day Pitney LLP
555 11th Street NW
Washington, DC 20004
(202) 218-3905
mwilliams@daypitney.com

Attorney for Vandolah Power Company L.L.C.

Jeffrey M. Jakubiak
Ankush J. Joshi
Vinson & Elkins LLP
1114 Avenue of the Americas, 32nd Floor
New York, NY 10036
(212) 237-0082
jjakubiak@velaw.com
ajoshi@velaw.com

Justin Moeller
Assistant General Counsel
Florida Power & Light Company
801 Pennsylvania Avenue NW, Suite 220
Washington, DC 20004
(202) 349-3346
justin.moeller@fpl.com

Attorneys for Florida Power & Light Company

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APPLICATION FOR APPROVAL PURSUANT TO SECTION 203 OF THE FEDERAL POWER ACT

Pursuant to section 203(a)(1) of the Federal Power Act ("FPA")[1] and Part 33 of the regulations of the Federal Energy Regulatory Commission ("FERC" or the "Commission"),[2] Vandolah Power Company L.L.C. ("Vandolah Power") and Florida Power & Light Company ("FPL" and, jointly with Vandolah Power, "Applicants") hereby submit this application ("Application") seeking all authorizations necessary to permit FPL: (i) to acquire Vandolah Power, the owner of the natural gas/oil-fired 660 MW (summer) Vandolah Generating Facility ("Vandolah") and, immediately thereafter, (ii) to merge Vandolah Power into FPL, resulting in FPL becoming the direct and sole owner of Vandolah (collectively, the "Transaction"). Applicants respectfully request: (a) a 30-day notice period and (b) an order approving the Transaction by December 8, 2025.

As demonstrated herein, the Transaction will not have any adverse effect on competition, rates, or regulation, nor will it result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company.[3]

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[1] 16 U.S.C. § 824b(a)(1) (2025).

[2] 18 C.F.R. Part 33 (2024).

[3] *See* 18 C.F.R. §§ 2.26(b) & (f). *See also Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 (1996) ("Order No. 592"), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997); *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 (2007), *order on clarification and reconsideration*, 122 FERC ¶ 61,157 (2008).

First, FPL is acquiring Vandolah to meet forecasted increases in load in the FPL balancing authority area ("BAA"). Any Competitive Analysis Screen failures are thus the result of FPL's Available Economic Capacity ("AEC") increasing, and are not the result of the elimination of any competitor of FPL.

Second, the Transaction will be advantageous to FPL's customers because it will displace an equivalent amount of higher-cost capacity resources that FPL would otherwise need to add to its system to meet growing demand. More particularly, acquiring Vandolah will displace 400 MW of four-hour batteries scheduled to enter service by January 1, 2028, and 475 MW of gas combustion turbines scheduled to enter service by January 1, 2032 (collectively, the "Avoided Capacity"). Absent the Transaction, both these batteries and combustion turbines would otherwise be built by FPL pursuant to its current Ten Year Site Plan filed with the Florida Public Service Commission ("Florida PSC") on April 1, 2025 (the "2025 TYSP").[4] FPL has estimated that acquiring Vandolah results in approximately $32 million in customer savings compared to constructing the Avoided Capacity.[5]

Third, as detailed below, FPL is willing, if required by the Commission, to commit to behavioral mitigation in the form of a day-ahead "must-offer" requirement of up to 330 MW of output from Vandolah in order to mitigate any temporary increase in market concentration above the Commission's thresholds that may arise as a result of the Transaction.

For these reasons, the Commission should approve the Transaction as consistent with the public interest.

[4] A copy of the 2025 TYSP is provided as Exhibit AWW-1 ("Exh. AWW-1") to the attached Prepared Direct Testimony and Exhibits of Andrew W. Whitley, Appendix 2 hereto ("Whitley Testimony").

[5] Whitley Testimony at 3, 16-17. This figure represents cumulative present value of revenue requirements ("CPVRR"), as discussed further in the Whitley Testimony.

I. DESCRIPTION OF PARTIES TO THE TRANSACTION

A. FPL and Relevant Affiliates

FPL is a vertically-integrated utility that provides regulated electric service to more than six million retail customers. FPL's retail service territory consists of an approximately 35,000 square mile area and a population of approximately 12 million people in peninsular Florida and the Florida panhandle. In addition, FPL sells wholesale power to other utilities and power marketers at locations in the southeastern United States.

FPL owns or controls approximately 35,531 MW of nameplate generating capacity, all but 215 MW of which are located in Florida. FPL's transmission facilities in peninsular Florida and the Florida panhandle are operated and administered pursuant to the FPL Open Access Transmission Tariff ("OATT"), which is on file with the Commission.[6] The Commission has granted FPL market-based rate authority in certain BAAs.[7] FPL is subject to regulation by the Florida PSC with respect to retail electric rates, the issuance of securities, affiliate transactions, the maintenance of books and records, and other matters.

FPL is a wholly-owned subsidiary of NextEra Energy, Inc. ("NextEra"), a Florida corporation and electric utility holding company, whose shares are publicly traded on the New York Stock Exchange.[8] In addition to FPL, NextEra owns NextEra Energy Resources, LLC

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[6] FPL FERC Electric Tariff, 2nd Revised Volume No. 6.

[7] *Florida Power & Light Co.*, 81 FERC ¶ 61,107 (1997).

[8] On April 30, 2025, The Vanguard Group, Inc. ("Vanguard") reported to the Commission on behalf of its subsidiaries and affiliated investment companies and funds that as of the end of the fourth quarter of 2024, Vanguard held 10.55 percent of the outstanding shares of NextEra Energy, Inc. *See* The Vanguard Group Inc. *et al.*, Docket No. EC19-57-002, Quarterly Compliance Filing for Q1 of 2025 (filed Apr. 30, 2025). As a result, as of the end of the first quarter of 2025, Vanguard is an Ultimate Upstream Affiliate of NextEra under the Commission's regulations. Applicants do not have knowledge of the actual number of outstanding shares currently held by Vanguard. To the best of Applicants' knowledge, there is no other entity that holds 10 percent or more of the outstanding voting securities of NextEra. *VESI 12, LLC*, 186 FERC ¶ 61,137 at P 16 (2024). Vanguard and its affiliates are a leading mutual fund complex and provider of low-cost index funds which seek to track the performance of a specified referenced index. Vanguard represents that it has no outside owners, and it is wholly and jointly owned by 37 affiliated investment companies in the Vanguard funds complex. *See The Vanguard Group, Inc.*, Docket No. EC19-57-000, Request for Blanket

("NEER"), whose subsidiaries own or operate merchant generating facilities in 38 states and Canada, with a combined net generating capacity of approximately 33,000 MW, including interests in some facilities co-owned by XPLR Infrastructure Operating Partners, LP ("XPLR").[9] As relevant to this transaction, NEER owns certain generation resources in the Southeast, including in Florida, which are described in Exhibit B.

NextEra also owns NextEra Energy Transmission, LLC, which, through its subsidiaries, owns New Hampshire Transmission, LLC ("NHT"), Trans Bay Cable LLC ("Trans Bay"), Horizon West Transmission, LLC ("Horizon West"), NextEra Energy Transmission MidAtlantic, Inc. ("NEET MidAtlantic"), GridLiance High Plains LLC ("GridLiance HP"), NextEra Energy Transmission Southwest, LLC; ("NEET SW"), NextEra Energy Transmission New York, Inc. ("NEET NY"), GridLiance West, LLC ("GridLiance West"), and GridLiance Heartland LLC ("GridLiance Heartland").[10]

- NHT is an electric utility that owns a single transmission asset, the Seabrook Substation, located in Seabrook, New Hampshire. NHT provides wholesale transmission service to its affiliate, NextEra Energy Seabrook, LLC, through a Local Network Service Tariff on file with the Commission.[11] ISO New England has operational control of the regional transmission facilities associated with the Seabrook Substation.[12]

Authorizations to Acquire Securities Under Section 203(a)(2) of the Federal Power Act, at 5-6 (filed Feb. 15, 2019). The Commission has granted Vanguard blanket authorization under FPA section 203(a)(2) to acquire the securities of any individual publicly traded U.S. utility, either up to 20 percent ownership in aggregate or up to 10 percent ownership by any individual Vanguard fund. *The Vanguard Group, Inc.*, 168 FERC ¶ 62,081 at 64,221 (2019). To receive such blanket authorization, Vanguard committed not to exercise any control over the day-to-day management or operations of any such publicly traded U.S. utility whose securities are acquired pursuant to the blanket authorization (except pursuant to a separate FPA section 203 authorization).

[9] XPLR was formerly known as NextEra Energy Partners, LP and is a publicly traded limited partnership whose common units are traded on the New York Stock Exchange.

[10] NextEra Energy Transmission Midwest, LLC has submitted a formula rate template with the Commission; however, it does not currently own, control, or operate transmission facilities.

[11] New Hampshire Transmission, LLC, FERC Electric Tariff No. 3.

[12] ISO New England Inc., FERC Electric Tariff No. 3, Schedule 21 NHT, Original Sheet No. 4200.

- Trans Bay is a public utility that owns and operates a 53-mile, approximately 400 MW high-voltage direct current submarine transmission line buried beneath the San Francisco Bay ("Trans Bay Cable").[13] The Trans Bay Cable is under the California Independent System Operator's ("CAISO") operational control, and service is provided pursuant to the CAISO OATT.

- Horizon West is a public utility that owns and operates the Suncrest project, a 230 kV +300/-100 MVAr Dynamic Reactive Power Support Project in southern California. The Suncrest project is under the CAISO's operational control, and service is provided pursuant to the CAISO OATT.

- NEET MidAtlantic owns approximately 20 miles of 345 kV transmission lines, and related equipment, which is under PJM's operational control, and service is provided pursuant to the PJM OATT.

- GridLiance HP owns and operates transmission assets in Oklahoma and Kansas. In Oklahoma, GridLiance HP owns approximately 424 miles of transmission lines and other facilities operated at 115 kV and 69 kV which are subject to GridLiance HP's OATT and a Wholesale Distribution Service Agreement and Wholesale Distribution Operating Agreement between GridLiance HP and Tri-County. In Kansas, GridLiance HP owns a 65 percent interest in the City of Winfield, Kansas' 69 kV transmission system and related substation equipment, which are under the Southwest Power Pool's ("SPP") control and subject to the SPP OATT as part of Zone 14.

- NEET SW owns and operates the Minco-Pleasant Valley-Draper project, a 48-mile, 345 kV transmission facility in Oklahoma, which is under the functional control of SPP.

- NEET NY owns the Empire State Line, a 20-mile, 345 kV transmission line, and related equipment, which is under the New York Independent System Operator's ("NYISO") operational control, and service is provided pursuant to the NYISO OATT.

- GridLiance West owns and operates a High Voltage Transmission System ("HVTS") consisting of approximately 165 miles of 230-kV transmission lines and related substation infrastructure that runs through rural southern Nevada. The HVTS has been incorporated into the CAISO-controlled grid and is subject to the terms of the CAISO OATT.

- GridLiance Heartland owns and operates six 161 kV transmission lines ranging from eight to 10 miles in length, two 161 kV substations, and associated auxiliary equipment in Kentucky and Illinois, which are under Midcontinent Independent System Operator, Inc.'s functional control.

[13] *NextEra Energy Transmission, LLC*, 166 FERC ¶ 61,188 at P 7 (2019).

Finally, NextEra and XPLR, through their subsidiaries, hold interests in several Commission-regulated interstate natural gas pipelines.[14] NextEra indirectly owns 42.5 percent of Sabal Trail Transmission, LLC ("Sabal Trail"). Sabal Trail is an approximately 515-mile-long interstate natural gas pipeline that begins in Alabama and terminates in central Florida. In addition, NextEra indirectly owns 100 percent of Florida Southeast Connection, LLC ("FSC"). FSC is an approximately 169-mile-long interstate natural gas pipeline that interconnects with Sabal Trail in central Florida and terminates in Riviera Beach, Florida. NextEra also indirectly owns 33.2 percent of Mountain Valley Pipeline, LLC ("Mountain Valley"). Mountain Valley is an approximately 303-mile-long interstate natural gas pipeline that begins in West Virginia and terminates in Virginia at Transcontinental Gas Pipe Line Company, LLC's ("Transco") Station 165. Finally, NextEra and XPLR indirectly own a 39.2 percent undivided interest in Meade Pipeline Co. LLC ("Meade"), which comprises approximately 185 miles of interstate natural gas pipeline facilities in Pennsylvania. Meade leases 100 percent of its facilities to Transco, which operates the pipeline facilities.

Additional relevant energy subsidiaries and energy affiliates of FPL are described greater detail in Exhibit B.

B. Vandolah Power

Vandolah Power owns the four unit, natural gas/oil-fired Vandolah electric generation facility in Wauchula, Florida with a summer net capacity of approximately 660 MW.[15] Vandolah is an exempt wholesale generator ("EWG") under the Public Utility Holding Company Act of

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[14] *Florida Se. Connection, LLC*, 154 FERC ¶ 61,080 (2016), *order on reh'g*, 156 FERC ¶ 61,160 (2016).

[15] Vandolah Power and Vandolah are reported in the Commission's market-based rate database as Utility ID 39125 and Plant Code 55415.

2005[16] that holds market-based rate ("MBR") authority,[17] and that is presently interconnected only to the transmission facilities of Duke Energy Florida, Inc. ("DEF").[18] All of Vandolah Power's capacity and energy are fully committed for sale exclusively to DEF under a long-term tolling agreement that remains in effect, under its own terms, to and through May 31, 2027. Vandolah Power does not own, manage, or control transmission facilities, but for its own limited and discrete interconnection facilities that link Vandolah to DEF's transmission system.

Vandolah Power does not own or control any transmission facilities other than the interconnection facilities necessary to interconnect Vandolah to DEF's transmission system. The generator interconnection facilities that Vandolah Power owns and controls are limited and discrete radial facilities that do not form an integrated transmission grid and that are used solely to interconnect Vandolah to the grid. Vandolah Power holds the priority rights and waivers set forth in Order No. 807,[19] such that Vandolah and its affiliates are immune from the Open Access Requirements to the extent set forth under Order No. 807.

Vandolah Power is a limited liability company formed under the laws of Delaware. Vandolah Power is a wholly-owned subsidiary of Vandolah Holding Company, L.L.C. ("Vandolah Holding"), which is a special-purpose holding company, the sole purpose of which is ownership of interests in Vandolah Power. NSG Vandolah Holdings LLC holds 100 percent of the interests

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[16] *See Vandolah Power Co., L.L.C.*, 99 FERC ¶ 62,098 (2002) (finding Vandolah to be an EWG).

[17] *See Vandolah Power Co., L.L.C.*, Docket No. ER10-2211-000, unpublished order dated Sept. 15, 2010 (accepting baseline filing of MBR tariff); *Vandolah Power Co., L.L.C.*, Docket No. ER10-2211-009, unpublished order dated May 15, 2025 (accepting for filing 2023 triennial market power update).

[18] *See* DEF S.A. No. 135, FERC Docket No. ER20-397-000 (amending and restating prior large generator interconnection agreement previously filed in Docket No. ER08-48); *Duke Energy Florida, LLC*, Docket No. ER20-397-000, unpublished letter order dated Jan. 10, 2020 (accepting for filing amended and restated large generator interconnection agreement). As discussed herein, on or about the date of consummation of the Transaction, FPL will directly interconnect Vandolah with its transmission system.

[19] *Open Access and Priority Rights on Interconnection Customer's Interconnection Facilities*, Order No. 807, 150 FERC ¶ 61,211 (2015).

in Vandolah Holding. NSG Vandolah Holdings LLC is a wholly-owned subsidiary of NSG Holdings II LLC, which is a wholly-owned subsidiary of NSG Holdings LLC, which is a wholly-owned subsidiary of NSG Power Holdings LLC, which is a wholly-owned subsidiary of Northern Star Generation LLC ("NSG").

1. NSG

NSG is an owner of electric power generation facilities in the United States, and NSG's affiliate, Northern Star Generation Services Company LLC, provides certain administrative and management services to certain NSG-owned facilities. NSG is not a "holding company" of any "electric utility" (as that term is defined under section 3 of the FPA) or any "public utility" which has a franchised retail service territory, has any "captive customers" (as that term is defined under Order No. 697), or which is engaged in the state-regulated sale of electricity at retail. NSG is not a "holding company" of any "electric utility" or any "public utility" which owns, operates, or controls electric transmission rights or electric transmission facilities (other than limited facilities used solely for the interconnection of generating facilities to the transmission grid). NSG does not own or control any electric facilities or essential inputs to electric generation[20] located in the United States. NSG is a holding company solely of EWGs and qualifying facilities ("QFs").

Vandolah Power, through NSG, is affiliated with one qualifying facility in the relevant BAA, Orange Cogeneration Limited Partnership ("Orange"). Orange is the owner of a gas-fired qualifying cogeneration facility with a maximum installed capacity of approximately 110.6 MWac, which is fully committed for sale at wholesale to DEF under a firm,

[20] *See* 18 C.F.R. §33.4(a). In addition, pursuant to section 35.36 of the Commission's regulations, essential inputs to generation include intrastate natural gas transportation, intrastate natural gas storage or distribution facilities, sites for generation capacity development, or sources and the transportation of coal supplies.

long-term, exclusive power sale agreement.[21] Orange is 100 percent owned and controlled by NSG. Through NSG, Vandolah Power has no affiliates (apart from Vandolah Power) that are reportable under Order No. 816-A at P 23 and that are located and/or operate within or first tier to the DEF BAA.

NSG is a limited liability company organized under the laws of the State of Delaware and headquartered in Houston, Texas. Fifty percent of the outstanding ownership interest in NSG is held by wholly-owned subsidiaries of the AIIF ("Archmore International Infrastructure Fund") I Purpose Trust under the control of Mourant Corporate Trustee (Jersey) Limited.[22] The remaining 50 percent ownership interest in NSG is held, through intermediate holding company subsidiaries, (i) 75 percent by a fund controlled by Harbert Management Corporation ("HMC"), approximately 98.75 percent of which is controlled by the California Public Employees Retirement System, and (ii) 25 percent by a separate fund, also controlled by HMC.

2. HPF V and Affiliates

Harbert Power Fund V, LLC ("HPF V")[23] is the 25 percent owner of GulfSun Power Holdings, LLC ("GulfSun Power"), which owns 50 percent of the issued and outstanding membership interests in NSG. GulfSun Power is a Delaware limited liability company organized as an investment fund and managed by Harbert Gulf MM, LLC ("Harbert Gulf MM"), which is a subsidiary of HMC. As stated above, GulfSun Power is owned and controlled by HPF V (25 percent) and Gulf Pacific Power, LLC ("Gulf Pacific") (75 percent). HPF V is a Delaware limited

[21] *See generally*, Docket No. QF93-164.

[22] *See Vandolah Power Co., L.L.C.*, 179 FERC ¶ 62,169 (2022).

[23] Investors in HPF V that hold, directly or indirectly, greater than 10 percent of the voting securities of HPF V are California Public Employees Retirement System ("CalPERS") and investment vehicles managed and controlled by Pantheon Ventures (US) LP ("Pantheon US"). Pantheon US does not hold other interests in Commission jurisdictional assets and is not affiliated with a public utility with a franchised electric service territory in the United States or inputs to power production.

liability company organized as an investment fund and managed by Harbert Power MM V, LLC ("Harbert Power MM V"), also a subsidiary of HMC. HPF V was formed to acquire, hold, operate, manage, and dispose of securities of EWGs, QFs, and related power assets and is a holding company solely with respect to such interests. Certain institutional investors, including pension funds, insurance companies, family offices, foundations, and affiliates' partners, have committed capital to HPF V in exchange for membership interests.[24] HMC is an Alabama corporation and an institutional investment manager subject to regulation by the Securities and Exchange Commission. HMC is largely owned and controlled by Mr. Raymond J. Harbert and members of his immediate family, with no one person or entity (but for Mr. Harbert and his immediate family members) owning or controlling, with power to vote, 10 percent or more of the voting securities of HMC.[25]

Gulf Pacific is a Delaware limited liability company organized as an investment fund and managed by Harbert Gulf MM, a subsidiary of HMC. Gulf Pacific was formed to acquire, hold, operate, manage and dispose of securities of EWGs, QFs (none of which are in the relevant market but for Vandolah Power), and related power assets on behalf of its investor members, and is a holding company solely with respect to ownership of EWGs and QFs.[26]

The California Public Employees Retirement System ("CalPERS") owns an approximately 98.75 percent interest in Gulf Pacific, and no other member owns or holds 10 percent or more of the

[24] *See Data Collection for Analytics & Surveillance and Market-Based Rate Purposes*, Order No. 860, 168 FERC ¶ 61,039 at P 138 (2019) ("Order No. 860"), order on reh'g and clarification, Order No. 860-A, 170 FERC ¶ 61,129 at P 15 (2020)("Order No. 860-A").

[25] *See* Order No. 860 at P 5 n.10; Order No. 860-A at n.9.

[26] Neither Gulf Pacific nor any affiliates thereof is a "holding company" of any "electric utility" (as that term is defined under section 3 of the FPA) or any "public utility" that has a franchised retail service territory, has any "captive customers" (as that term is defined by the Commission), or is engaged in the state-regulated sale of electricity at retail. Neither Gulf Pacific nor any affiliates thereof is a "holding company" of any "electric utility" or any "public utility" that owns, operates or controls electric transmission rights or electric transmission facilities (other than limited facilities used solely for interconnection).

voting or equivalent interests in Gulf Pacific. Gulf Pacific may not take certain actions without the prior approval of CalPERS, but Harbert Gulf MM otherwise manages, controls, and administers the operations of Gulf Pacific. CalPERS also holds more than 10 percent of the investment interests in HPF V. Neither Gulf Pacific nor any affiliates thereof owns or controls any electric generation, transmission, or distribution facilities (other than QFs and EWGs) or essential inputs to electric generation.

CalPERS is administered by the State of California and is the nation's largest public pension fund with a current total fund market value of approximately $514.5 billion.[27] CalPERS' investments span domestic and international markets. From time to time CalPERS may, as part of its investment strategies, directly or indirectly hold passive debt and/or equity investments in energy related assets. CalPERS holds such investments in its capacity as a passive limited partner in various third-party investment funds. CalPERS owns a non-managing interest in Gulf Pacific and has veto rights on major decisions to protect its economic interest.

CalPERS holds no equity interests in any other generating facility within or first-tier to the relevant BAA. Neither CalPERS nor any of its affiliates owns or controls 10 percent or more of the voting securities in entities that own or control electric generation or transmission facilities, or inputs to electric power production, including in the relevant geographic market. In addition, neither CalPERS nor any of its affiliates is a franchised public utility.

3. Mourant Corporate Trustee (Jersey) Limited and AIIF I Purpose Trust

Mourant Corporate Trustee (Jersey) Limited, the ("Trustee") is regulated by the Jersey Financial Services Commission and is licensed to act as or fulfill the function of a trustee of a trust.

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[27] *See* https://www.calpers.ca.gov/investments. As stated above, CalPERS owns a non-managing interest in Gulf Pacific and has limited veto rights on major decisions to protect its economic interest. Nonetheless, Applicants have included information on CalPERS out of an abundance of caution.

It is controlled by its managing director (from time to time) who has responsibility for the day-to-day management of the Trustee, and is owned by a law firm in Jersey, Channel Islands, a Crown Dependency of the United Kingdom. The Trustee controls the AIIF I Purpose Trust, and the AIIF I Purpose Trust will itself own and hold nothing except the interests in the sole general partner that in turn controls Archmore, which holds 50 percent of the interests in NSG (and hence in Vandolah Power). The AIIF I Purpose Trustee is regularly engaged in acting as a trustee of trusts that own and hold securities, such as Archmore. The Trustee is not primarily engaged in the ownership or control of United States energy businesses or assets, and does not own, hold, or control generation, wholesale power agreements, transmission, or distribution facilities into or within the United States, or other vertical inputs to generation. The Trustee is owned by a law firm that practices in Jersey, Channel Islands, and no one person or entity ultimately owns or controls any interest of 10 percent or greater in the Trustee. The AIIF I Purpose Trust (via its ownership of the general partner of Archmore) ultimately manages and controls Archmore.

II. DESCRIPTION OF THE TRANSACTION

A. Background

The context and reasons for the Transaction are detailed in the Testimony of Andrew Whitley, Integrated Resource Planning Manager at FPL, attached at Appendix 2 hereto.

As explained by Mr. Whitley, the Transaction is a central part of FPL's effort to expand its generation portfolio to meet its forecasted increase in load in a manner that benefits its customers in terms of both reliability and cost.[28] As detailed in the 2025 TYSP, FPL's peak summer demand increased by 2,905 MW between 2015 and 2024, and is expected to increase by another 3,411 MW

[28] Whitley Testimony at 13.

over the next 10 years.[29] This projected increase is driven primarily by new Floridians and traditional businesses that are moving into FPL's service territory, and will lead to capacity shortfalls if additional resources are not added.[30] Something must done by FPL to meet its resource needs.

The 2025 TYSP outlines a viable plan to satisfy the forecasted increase in load between 2025 and 2034 through a combination of: (i) new solar generation (17,433 MW), (ii) new battery storage (7,603 MW), (iii) new combustion turbines (475 MW), and (iv) upgrades to existing combined cycle generating facilities (80 MW).[31] FPL has determined, however, that Vandolah could substitute for certain of these new resources at a lower overall cost, while supplying an equivalent amount of capacity, thereby benefiting ratepayers.

Indeed, as explained by Mr. Whitley, ownership and operation of Vandolah will supplant the need for the Avoided Capacity—*i.e.*, 400 MW of new four-hour batteries scheduled to enter service by January 1, 2028, and two combustion turbines totaling 475 MW that are scheduled to enter service by January 1, 2032, at FPL's Manatee Station.[32] The substitution of Vandolah for the Avoided Capacity will result in approximately $32 million in savings over the life of these assets compared to the 2025 TYSP.[33]

In addition, acquiring Vandolah as of the date the DEF Tolling Agreement expires (June 1, 2027) will provide FPL with generating capacity faster than pursuing the Avoided

[29] 2025 TYSP at 61-62, Schedule 3.1 (Forecast of Summer Peak Demand (MW)) (Exh. AWW-1 at 74-75). More particularly, FPL forecasts that summer peak load will increase to 31,677 MW in 2034, a 3,411 MW increase from actual peak load of 28,266 in 2024.

[30] Whitley Testimony at 5.

[31] 2025 TYSP at 5, 16 (Exh. AWW-1 at 18, 29).

[32] Whitley Testimony at 14-15; Oliver Testimony at 12-13.

[33] Whitley Testimony at 3, 16-17.

Capacity given current supply chain limitations and insulate customers from the risk of pricing volatility, tariffs, permitting delays, changes in tax policy, and other risk factors inherent to the development of new utility infrastructure.[34]

The present Transaction will thus inure directly to the benefit of FPL's customers. FPL respectfully asks the Commission to consider the Transaction now, in 2025, even though the Transaction will not close until June 1, 2027, to allow sufficient time for FPL to develop the Avoided Capacity that its customers will need if for some reason the Transaction is not approved.

B. The Transaction

The Transaction will be consummated in accordance with the Purchase and Sale Agreement by and between Vandolah Holding and FPL dated as of April 9, 2025 (the "PSA"). More particularly, FPL will: (i) acquire Vandolah Power from Vandolah Holding and then immediately (ii) merge Vandolah Power into FPL, resulting in FPL becoming the direct and sole owner of the Vandolah facility. Upon consummation, Vandolah Holding, NSG, and their owners will cease to control or be affiliated with Vandolah and Vandolah's jurisdictional facilities. Applicants currently anticipate the Transaction being consummated on June 1, 2027 (the day after the DEF Tolling Agreement expires).

In order to integrate Vandolah directly into the FPL BAA, FPL will build a new transmission substation (the Bickett Substation) and construct an approximately 14.5-mile, 230 kV transmission line to directly interconnect Vandolah to the FPL transmission system (the "Vandolah Interconnection Line").[35] Once energized, which FPL expects to occur on or before the date of consummation of the Transaction, this line will serve as a direct interconnection of the FPL grid

[34] *Id.* at 17.

[35] *See* Oliver Testimony at 13-14.

to Vandolah, and FPL will re-register Vandolah with the North American Electric Reliability Commission ("NERC") as a generating resource in FPL's BAA.

III. REQUEST FOR AUTHORIZATION UNDER FPA SECTION 203

FPL respectfully requests that the Commission grant all authorizations necessary under FPA section 203 to effectuate the Transaction.[36]

Under FPA section 203(a), the Commission will approve a proposed transaction if it determines that it: (i) is consistent with the public interest; (ii) does not effect a cross-subsidization of a non-utility associate company that is not in the public interest; and (iii) does not pledge or encumber utility assets for the benefit of an associate company.[37]

With regard to whether a transaction is consistent with the public interest, the Commission applies a three-part test set forth in the Merger Policy Statement[38] and in Order No. 642.[39] Specifically, the Commission examines the effect of a proposed transaction on: (i) competition, (ii) rates, and (iii) regulation.[40] Applicants need not show that a transaction positively benefits the public interest, but rather simply that it is consistent with the public interest.[41]

As demonstrated in this Application, the Transaction will have no adverse effect in any of these areas and therefore is consistent with the public interest. Additionally, the Transaction will

[36] FPL believes that certain aspects of the Transaction may not require prior approval under FPA section 203 but nonetheless seeks, out of an abundance of caution, authorization for the Transaction as a whole, without asking the Commission to resolve any threshold jurisdictional issues. *See, e.g.*, *Ocean State Power*, 47 FERC ¶ 61,321 at 62,130 (1989) (assuming jurisdiction without resolving threshold question).

[37] 16 U.S.C. § 824b(a)(4).

[38] Order No. 592, FERC Stats. & Regs. ¶ 31,044 at 30,111.

[39] *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,874-78 (2000) ("Order No. 642"), *on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001); 18 C.F.R. § 33.2(g).

[40] 18 C.F.R. § 2.26(b).

[41] *See, e.g., Texas-New Mexico Power Co.*, 105 FERC ¶ 61,028 at P 23 & n.14 (2003) (citing *Pacific Power & Light Co. v. FPC*, 111 F.2d 1014, 1016-17 (9th Cir. 1940)).

not result in cross-subsidization of a non-utility associate company or a pledge or encumbrance of utility assets for the benefit of an associate company.[42] Accordingly, the Transaction should be approved.

A. The Transaction is Consistent with the Public Interest

1. The Transaction Will Have No Adverse Effect on Competition

In Order No. 642, the Commission stated that its objective in analyzing a proposed transaction's effect on competition is to determine whether such disposition "will result in higher prices or reduced output in electricity markets."[43] The Commission has ruled that higher prices and reduced output in electricity markets may occur if FPA section 203 applicants are able to exercise market power, either alone or in coordination with other firms.[44] As demonstrated herein, the Transaction will have no adverse effect on competition.

a. The Transaction Will Have No Adverse Effect on Horizontal Competition in Generation

FPL's acquisition of Vandolah and its subsequent transfer from the DEF BAA to the FPL BAA will have no adverse effect on horizontal competition in generation. FPL is the primary generator in the highly-concentrated FPL BAA, so virtually any increase in generation would create the appearance of anti-competitive effects indicated by increases in the Herfindahl-Hirschman Index ("HHI") in excess of the Commission's Competitive Analysis Screen thresholds.[45] However, the mere presence of screen failures does not indicate there are adverse horizontal competitive effects, particularly where, as here, the screen failures result from the addition of AEC rather than the elimination of a competitor or competitive supply.

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[42] *See* 18 C.F.R. § 2.26(f).

[43] Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,879.

[44] *Id.*

[45] *See* 18 C.F.R. § 33.3(c)(5) (requiring calculation of HHI statistics as part of Competitive Analysis Screen).

Osprey Energy Center, LLC ("*Osprey*")[46] and *Nevada Power Company* ("*Nevada Power*")[47] presented to the Commission transactions that are very similar to the one proposed here. Both of those transactions, like the present one, involved a vertically-integrated utility operating in a highly-concentrated, non-RTO market (*Osprey*, in fact, was in Florida), acquiring an existing generator in order meet capacity needs (either as a result of growing load or near-term generation retirements) as an alternative to constructing new generation. Notwithstanding Competitive Analysis Screen failures in the buyer utility's home market, the Commission held in *Osprey* that the proposed transaction "present[ed] a situation in which the change in HHI may overstate the effect on competition" and required no market-power mitigation measures.[48] In *Nevada Power*, the Commission recognized the temporary nature of the market power issues that were, in that transaction, comparable to those that are present here, and so only required behavioral, and not structural, mitigation.[49]

Tenaska Alabama Partners, L.P. ("*Tenaska*")[50] presented similar circumstances as well. Like *Osprey* and *Nevada Power*, that transaction, involved a vertically-integrated utility operating in a non-RTO market seeking to acquire an existing generator in order meet load growth in a more cost-effective manner than building generation or entering into a power purchase agreement.[51]

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[46] *Osprey Energy Ctr., LLC*, 152 FERC ¶ 61,066 at PP 17-18, 33 (2015) ("*Osprey*") (Commission finding that DEF's acquisition of the 590 MW Osprey Energy Center "does not raise horizontal market power concerns" notwithstanding a screen failure during summer off-peak period in a highly concentrated market, as well as additional screen failures in price sensitivity analyses).

[47] *Nevada Power Co.*, 157 FERC ¶ 61,094 (2016) ("*Nevada Power*").

[48] *Osprey* at P 34.

[49] *Nevada Power* at P 26.

[50] *Tenaska Alabama Partners, L.P.*, 191 FERC ¶ 61,190 (2025).

[51] *Id.* at P 41. *Tenaska Alabama Partners, L.P.*, Docket No. EC25-27-001, Supplemental Affidavit of Matthew E. Arenchild at 4 (Mar. 17, 2025) ("The acquisition of the Lindsay Hill Facility will provide a cost-effective means to contribute toward meeting these resource adequacy requirements, ensuring APC can continue to serve its customers reliably while avoiding higher-cost alternatives such as new-build generation or long-term power purchase agreements.")

And while market concentration was lower there than in *Osprey* or *Nevada Power*, still there were Competitive Analysis Screen failures. Nonetheless, the Commission approved the transaction without requiring mitigation measures,[52] noting, among other things, "evidence that [the utility buyer's] need for capacity is driven by load growth in its retail service territory" and applicants' argument that the proposed transaction "represents the most cost-effective alternative for customers as determined through [the utility's] competitive bidding process."[53]

Osprey, *Nevada Power*, and *Tenaska* can all be read for the proposition that, when a vertically-integrated utility in a non-RTO market acquires existing generation as cost-effective alternative to constructing new capacity needed to supply growing load or replace retiring generation, any Competitive Analysis Screen failures are, at worst, temporary and, to the extent necessary, can be addressed with behavioral, rather than structural, mitigation. It would therefore be fully consistent with this precedent for the Commission not to require any market power mitigation measures here or, if any are deemed necessary, limit such mitigation to a behavioral must-offer remedy.

While no mitigation was required in *Osprey* or *Tenaska*, if the Commission deems it necessary based on the particulars of this Transaction, FPL is willing to commit to certain behavioral mitigation after acquiring Vandolah. As detailed below, FPL is willing to commit to a day-ahead "must-offer" of at least 330 MW from Vandolah at cost-capped rates during all Summer and Shoulder season hours through at least May 31, 2030, or, if necessary, December 31, 2031. Just as in *Nevada Power*, any market power issues brought about by the present Transaction will only be temporary and will expire prior to the beginning of the Summer 2030 season, when new

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[52] *Id.* at 40.

[53] *Id.* at 41.

solar and battery storage could enter the market if development started on the date of closing of the Transaction, or new gas fired generation could enter the market if development started today. Further, any market power issues would expire, at the very latest, prior to January 1, 2032, when FPL would have placed the last of the Avoided Capacity in service but for the proposed Transaction. Thus, consistent with Commission precedent, a must-offer of this duration is appropriate mitigation, should any mitigation be needed at all.

Applicants thus respectfully submit that the Commission should approve the present Transaction promptly and without any condition of market power mitigation measures. However, if and to the extent necessary to obtain approval of the Transaction, FPL is willing to commit to the market power mitigation measures detailed below.

i. Competitive Analysis Screens Conducted

The Commission's regulations provide that a Competitive Analysis Screen should be conducted for "each wholesale power sales customer or set of customers (destination market) affected by the proposed transaction."[54] This rule is generally applied in the context of FPA section 203 applications by conducting the Competitive Analysis Screen for the BAA in which merging entities own or control electric generating capacity, as well as any other BAAs that may be materially impacted by the proposed transaction.

FPL retained Dr. John Morris to conduct Competitive Analysis Screens relevant to, and in support of, the present Application. The analyses conducted, and the results thereof, are described fully in Dr. Morris' Report and Affidavit, attached at Appendix 3 hereto. As noted above, Applicants anticipate consummating the Transaction on June 1, 2027, the day after the expiration

[54] 18 C.F.R. § 33.3(c)(2).

of the DEF Tolling Agreement. As a result, Dr. Morris conducted his analyses using a June 1, 2027, through May 31, 2028, test year.

Consistent with Commission precedent, Dr. Morris conducted Competitive Analysis Screens of the FPL BAA and all first tier BAAs showing the impact of the Transaction assuming that: (i) Vandolah moves from the DEF BAA in the pre-Transaction scenario to the FPL BAA in the post-Transaction scenario, and (ii) the output of Vandolah goes from being attributed to DEF to FPL. Dr. Morris refers to this set of Competitive Analysis Screens as the "Base Case."

In addition, in order to address the possibility that the new Vandolah Interconnection Line, directly connecting Vandolah to the FPL BAA, is not energized by time the Transaction closes, Dr. Morris also conducted Competitive Analysis Screens of the DEF BAA and all first tier BAAs showing the impact of the Transaction assuming that: (i) Vandolah remains in the DEF BAA in the pre- and post-Transaction scenarios, but (ii) the output of Vandolah goes from being attributed to DEF to FPL. Dr. Morris refers to this set of Competitive Analysis Screens as the "Alternate Case."

Further, in order to analyze the changes in market concentration that would occur if the Transaction did not occur and FPL instead constructed the Avoided Capacity, as contemplated in the 2025 TYSP, Dr. Morris conducted an analysis that he refers to as his "But-for" case—*i.e.*, what would be the change in market concentration "but for" the Transaction.

The results of these analyses are addressed separately below.

ii. Competitive Analysis Screen Results — Base Case

As detailed in his Affidavit and associated attachments, Dr. Morris' Base Case analysis (in which Vandolah moves from the DEF BAA to the FPL BAA) shows Competitive Analysis Screen failures for AEC[55] in the FPL BAA under base prices in only two periods—namely the Summer Top 10%, and Summer Top 1% periods.[56] Additional failures are observed in the Shoulder season and the Summer Peak and Off-Peak periods when assumed prices are increased by 10 percent.[57] In markets first tier to the FPL BAA, his analysis shows certain screen failures in the DEF, Florida Municipal Power Pool ("FMPP"), Gainesville Regional Utilities ("GVL"), Jacksonville ("JEA"), and Tallahassee ("TAL") BAAs.[58]

a) The Base Case Screen Failures Overstate Competitive Effects; the Transaction Should Be Approved Without Mitigation

The screen failures under the Base Case analysis should not cause the Commission concern. Indeed, the Commission stated in *Tenaska* that "when a proposed transaction has screen failures, applicants may provide factors specific to the proposed transaction that indicate that there will not be an ability and incentive to withhold output, and therefore the proposed transaction will not have an adverse impact on competition."[59] Such specific factors are present in the current proposed Transaction.

As explained by Dr. Morris, competitive supply does not decline because of the Transaction during the Summer Top 10% or Summer Top 1% periods.[60] "In fact, in the FPL BAA, which is the most relevant destination market for this analysis, competitive supply remains the

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[55] Insofar as Florida lacks retail competition, measures of Economic Capacity are not informative in assessing market power effects of the Transaction. *See, e.g., Duke Energy Corp.*, 136 FERC ¶ 61,245 at P 124 (2011) ("the AEC measure is more appropriate for markets where there is no retail competition and no indication that retail competition will be implemented in the near future"); *Nevada Power Co.*, 113 FERC ¶ 61,265 at P 15 (2005) (AEC is a more accurate measure for markets where utilities have significant native load obligations).

[56] *See* Morris Aff., Exh. JM-8 at 10. Dr. Morris sometimes refers to the Summer Top 10% and Summer Top 1% periods as SUM_T10 and SUM_T1, respectively.

[57] *Id.* at 29-31, Tables 8-10; *see also id.* Exh. JM-8 at 13. When prices are decreased by 10 percent, there are failures only in Summer Top 10% and Summer Top 1% periods. *Id.* at 30-31; Exh. JM-8 at 16.

[58] *Id.* at 36-37; *see also id.* Exh. JM-8.

[59] *Tenaska* at P 41.

[60] *Id.* at 9, 31.

same during the time periods in which the DPT screen fails.... In other words, the DPT results indicate that wholesale buyers within the FPL BAA are not adversely affected; they have access to the same levels of competitive supply post-Transaction."[61] Thus, these screen failures are "best understood as false positives."[62]

Osprey presented facts similar to those present here and, in that case, the Commission found that no market power mitigation measures were necessary. The same finding should be made here—that market power mitigation measures are unnecessary.

First, like Duke Energy in *Osprey*,[63] FPL is a vertically integrated utility that operates in a "thin," concentrated, non-RTO market where virtually any increase in generation capacity would result in screen failures. Indeed, in the Summer Top 1% period, the approximately 584 MW of additional AEC supply resulting from the Transaction increases FPL's market share from 78.2 percent to 81.4 percent, with a corresponding HHI increase of 481 points.[64] Importantly, competitive supply—defined as AEC not affiliated with FPL from internal sources or imports—does not decline. Still, this change results in a screen failure. In this regard, as explained by Dr. Morris, the screen failures constitute "false positives."[65]

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[61] *Id.* at 9-10.

[62] *Id.* *See also id.* at Table 12.

[63] *See Osprey* at P 17 (discussing screen failure during summer off-peak timer period with HHI increase of 100 in a highly concentrated market) and P 36 (noting "thin[ness]" of wholesale market). In *Osprey*, pre-transaction AEC HHIs in the DEF BAA ranged from 1,501 to 7,110 in the Summer and Winter seasons, indicating a concentrated or highly-concentrated market (although HHIs were considerably lower in the Shoulder season). *Osprey Energy Center, LLC et al.*, Docket No. EC15-96-000, Joint Application for Approval Under Section 203 of the Federal Power Act and Request for Shortened Comment Period of Osprey Energy Center, LLC and Duke Energy Florida, Inc., Testimony of Julie R. Solomon at 8, Table 3 (Mar. 13, 2015) ("*Osprey* Application").

[64] Morris Aff. at Table 2. Similarly, in the Summer Top 10% period, the pre-Transaction HHI exceeds 6,400 points and the Transaction would increase FPL's market share from 79.2 percent to 82.5 percent. *Id.*

[65] *See id.* at 9, 31-32.

Second, as also in *Osprey*,[66] no competitor in the FPL BAA would be eliminated by the Transaction. For one, Vandolah does not compete with FPL. Rather, the output of Vandolah is fully committed to DEF which, on information and belief, uses the output to serve native load in the DEF BAA. In addition, DEF does not compete with FPL in the FPL BAA in more than a *de minimis* respect. More particularly, in 2023-2024, DEF sold only 1,323 MWh in the FPL BAA. By contrast, 3.24 million MWh of energy were sold at wholesale in the FPL BAA in 2024.[67] The sales by DEF thus represented merely 0.04 percent of the total wholesale market—a truly *de minimis* amount. [68] In any event, DEF will not be eliminated but rather will continue to exist after the Transaction. FPL purchasing Vandolah therefore does not eliminate a competitor in the FPL BAA, nor does it eliminate a meaningful amount of competitive supply.

Third, as in *Osprey*,[69] the observed increases in HHIs resulting from the Transaction are attributable solely to an increase in AEC in the FPL BAA—which is decidedly *pro*-competitive.[70] The observed increases are not related to the elimination of a competitor or reduction in a competitor's wholesale market share. In *Osprey*, the Commission recognized that the effect of the proposed transaction on the market was not substantially different than Duke Florida's alternative of building the Suwannee Combustion Turbines, among other factors.[71] Here, as explained by Dr.

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[66] *See Osprey* at P 21 (noting applicants' discussion that the proposed transaction does not eliminate a competitor in the DEF BAA) and P 34 (Commission stating "a competitor in the market is not being eliminated").

[67] *See* Morris Aff. at 41; Exh. JM-13.

[68] *See Nw. Corp.*, 136 FERC ¶ 62,088 (2011) (approving a section 203 application without a Competitive Analysis Screen, based on the applicants' representation that the generating plant being acquired represented less than two percent of installed capacity in the relevant market, and was therefore *de minimis*).

[69] *Osprey* at P 34 ("As Applicants note, the increase in Duke Florida's market share is driven largely by the increase in its available economic capacity that is entering the market. There is no corresponding reduction in available economic capacity in the market because a competitor in the market is not being eliminated.).

[70] *See* Morris Aff. at 11 ("an increase in HHI may overstate the transaction's competitive impact if the merging party's gain in market share is primarily due to the addition of new available economic capacity, rather than the elimination of a competitor").

[71] *Osprey* at P 34, 35.

Morris in his discussion of his "But-for" analysis, the effect of the proposed Transaction on the market is not substantially different from FPL following its current plan of constructing the Avoided Capacity.[72]

Fourth, in both *Osprey* and this Transaction (as well as in *Tenaska*), the buyer is acquiring a moderately sized gas-fired, merchant generating facility in order to meet the needs of growing load and as a cost-effective alternative to constructing new generation, which otherwise would have been needed to meet the growing load.[73] In the present case, as explained by Mr. Whitley, purchasing Vandolah will result in savings to FPL's customers of approximately $32 million (on a net present value basis) as compared to the alternative of constructing the Avoided Capacity contemplated in FPL's 2025 TYSP.[74]

Fifth, like Duke Energy in *Osprey*,[75] FPL lacks market-based rate authority in the FPL BAA. In the Supplemental Policy Statement, the Commission stated that "in horizontal mergers, if an applicant fails the Competitive Analysis Screen…, the Commission's analysis focuses on the merger's effect on the merged firm's *ability* and *incentive* to withhold output in order to drive up the market price."[76] Thus, even if the Transaction did increase FPL's generation market power in

[72] *See* Morris Aff. at 11 ("the competitive effect of the proposed transaction may be similar to that of an alternative scenario—for example, where the merging party meets its future load obligations by building new supply rather than acquiring existing assets").

[73] In its application, Duke Energy Florida's experts stated that acquiring Osprey Energy Center is $61 million more cost-effective based on a Cumulative Present Value Revenue Requirements analysis than constructing the Suwannee Combustion Turbines. *See Osprey* Application at 35. *See also Tenaska Alabama* at P 41.

[74] Whitley Testimony at 3, 16-17.

[75] *Osprey* at P 19.

[76] *FPA Section 203 Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 at P 60 (2007) (emphasis in original).

some regard, FPL lacks any ability to raise prices as a result of any such increase (or to capitalize on any price increases that might otherwise occur).[77]

Sixth, the additional screen failures when prices are increased by 10 percent should not cause the Commission concern. The Commission has in the past indicated that it focuses its analysis on "persistent" screen failures.[78] The screen failures in the Shoulder season and the Summer Peak and Off-Peak periods only occur when assumed prices are increased by 10 percent. They do not occur with base prices, or when prices are decreased by 10 percent. These screen failures are thus not persistent, and the Commission should look past them.

Seventh, the screen failures in markets other than the FPL BAA should not cause concern because, in the words of Dr. Morris, they are "false positives" driven in large part by changes in Simultaneous Import Limits ("SILs").[79] As explained by Dr. Morris, some of these screen failures are a result of SIL increases, which increase the FPL AEC in the destination market, but also increases the AEC of competing generation. "These are false positives because the supplies of others are not diminished."[80] Other screen violations are the result of the SIL decreasing, resulting in less first tier generation reaching the destination market, and so the market share of the "home" utility increases. But, again, these are false positives because they "do not indicate the potential for FPL to raise prices anticompetitively from the Transaction."[81] Thus, these screen failures in markets other than the FPL BAA should not cause the Commission concern.

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[77] *See* Morris Aff. at 14 ("[B]oth federal and state regulations significantly constrain any potential [by FPL] to raise market prices. FPL lacks authority to make wholesale sales at market-based rates within the FPL, Homestead, FMPP, and Gainesville BAAs."). *See, however*, *Nevada Power Co.* at P 22 ("While the lack of market-based rates is a mitigating factor, it does not overcome the competitive concerns raised by the increase in market concentration as a result of the Proposed Transaction.").

[78] *See, e.g.*, *Nevada Power* at P 26.

[79] Morris Aff. at 32.

[80] *Id.*

[81] *Id.*

The Commission held in Order No. 642 that it has the right to look beyond the HHI screen failures and focus its analysis on the "merger's effect on the merged firm's ability and incentive to withhold output in order to drive up market price" instead.[82] In *Osprey*, the Commission did exactly that and held that the transaction did not raise horizontal market concerns because the increase in DEF's market share was driven by the increase in AEC entering the market, and there is no corresponding reduction in AEC because a market competitor is not being eliminated. Based on the similarities between *Osprey* and the present case, a similar finding that no mitigation is necessary here would be entirely appropriate.

b) Even if the Screen Failures Indicate Some Adverse Competitive Impact, Any Such Effects Are Temporary in Nature, Such that Behavioral Mitigation Would Be an Appropriate Remedy Under Commission Precedent

As discussed above and in the Whitley Testimony, FPL needs to increase its generating capacity in order to meet growing system load. FPL's latest ten-year site plan, filed with the Florida PSC on April 1, 2025, outlines a plan to satisfy the forecasted increase in load between 2025 and 2034 through a combination of: (i) new solar generation (17,433 MW), (ii) new battery storage (7,603 MW), (iii) new combustion turbines (475 MW), and (iv) upgrades to existing combined cycle generating facilities (80 MW).[83] With or without the present Transaction, FPL's generation fleet will need to increase.

The present Transaction merely results in FPL acquiring generation instead of constructing it. Indeed, the Transaction will substitute in FPL's resource plan an existing, newly-acquired generating facility for an equivalent amount of capacity that would otherwise be constructed by FPL. More particularly, as explained in the Whitley Testimony, if FPL acquires

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[82] *Supplemental Policy Statement*, FERC Stats. & Regs. ¶ 31,253 at P 60 (2008).

[83] 2025 TYSP at 5, 16 (Exh. AWW-1 at 18, 29).

Vandolah, the acquisition would replace the Avoided Capacity in FPL's 2025 TYSP—*i.e.* (i) 400 MW of four-hour batteries that would otherwise enter service by January 1, 2028, and (ii) 475 MW in new combustion turbines that would otherwise enter service by January 1, 2032.

In this regard, any perceived competitive harm from the Transaction indicated by the modeled increases in FPL's AEC (and associated HHI values) is temporary in nature because, absent the Transaction, FPL's AEC would have increased anyway through the construction of the batteries and combustion turbines that will no longer be needed following the Transaction. Indeed, as explained by Dr. Morris, post-Transaction HHI levels in the FPL BAA will be similar to or lower than what would result if FPL were to construct the Avoided Capacity rather than purchasing Vandolah, all else being equal.[84]

The ability of new, competing generation to enter the FPL market further ensures that any adverse competitive impact of the Transaction will be temporary. The Commission has recognized that market power concerns are not present in long-term capacity markets unless participants possess the ability to create barriers to entry.[85] And neither FPL nor any other market participant

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[84] Morris Aff. at 15 ("These results suggest that the Vandolah acquisition results in changes in market concentration that are similar to (or in fact less) than those that would be observed in the scenario in which the Transaction does not occur."). *See also Osprey* at P 21 ("Applicants assert that the results of the screens will not be materially different for a transaction in which Duke Florida builds a plant comparable to the Osprey Energy Center and Osprey continues to own and operate the Osprey Energy Center.").

[85] *NextEra Energy Inc.*, 165 FERC ¶ 61,199 at P 26 (2018) ("Generation Applicants state that the duration of the GE Lease is sufficient to address any horizontal market power concerns associated with the Generation Transaction because the potential for new market entry ensures that the long-term capacity market is competitive."); *Puget Sound Energy, Inc.*, 107 FERC ¶ 61,082 at P 18 (2004) ("Analysis of the long-term capacity market focuses on barriers to entry by new generators through an applicant's control of key inputs, principally sites for new capacity development and transportation systems for fuel supplies. While, as a result of the Transaction, PSE will be able to construct additional generating units at the Frederickson site, Applicants note that other generating facilities are also under construction or proposed at sites in or near the PSE control area."); *Delmarva Power & Light Co.*, 71 FERC ¶ 61,160 at 61,609 (1995) ("the applicants' summary of the results of recent new capacity solicitations by nearby utilities and their showing that the merged company will not be able to raise barriers to entry provide a sufficient basis to conclude that the merger will have no adverse competitive effects on long run generation markets"). *See also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Servs. by Pub. Utils.; Recovery of Stranded Costs by Pub. Utils. & Transmitting Utils.*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, 31,649, n.86 (1996) ("after examining generation dominance in many different cases over the years, we have yet to find an instance of generation dominance in long-run bulk power markets").

can erect barriers to entry.[86] Since 2015, approximately 7,900 MW of generating capacity owned by non-affiliates of FPL has entered service in Florida.[87] Thus, any concerns about market power need not extend to the long-term because competing generation can, and does, enter the marketplace. Specifically, as discussed below and in the attached testimony of Timothy Oliver, Vice President of Development for FPL, new solar generation paired with storage can enter the market in three years or less, while new combustion turbines can enter the market in three to five years.

In *Nevada Power*, the Commission confirmed that where adverse competitive effects are merely temporary, behavioral remedies are an appropriate form of mitigation. In that proceeding, the Commission reviewed a proposed purchase of a 550 MW generating facility by affiliates of Nevada Power Company and Sierra Pacific Power Company (jointly "NV Energy").[88] The applicants there explained that the Competitive Analysis Screen failures were the result of Nevada Power acquiring generation to replace capacity that would soon retire, and would continue until that generation did in fact retire. The applicants argued that behavioral mitigation—namely a "must-offer requirement"—need only continue until such retirements, because it "effectively maintains the status quo until such a time as specific resources leave the NV Energy fleet."[89] In

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[86] *See Bell Ridge Solar, LLC, et al.*, Docket Nos. ER23-883-001, *et al.*, Southeast Region Triennial Market Power Update, Filing Letter at 25-26 (June 30, 2023) (demonstrating inability of FPL and its affiliates to erect barriers to entry in the Southeast).

[87] *See* Energy Information Administration, Preliminary Monthly Electric Generator Inventory, EIA-860M for April 2025, https://www.eia.gov/electricity/data/eia860m/xls/april_generator2025.xlsx (culled for generating facilities in Florida entering service since 2015 by entities other than FPL and its affiliates).

[88] *See generally Nevada Power*, cited *supra*. *See also Nevada Power Co.* Order Accepting Compliance Filing, 158 FERC ¶ 62,077 (2017) ("*Nevada Power II*").

[89] *Nevada Power Co.*, Docket No. EC16-130-000; Application at 36 (June 7, 2016).

its order, the Commission agreed that, insofar as any "market power concern [was] temporary," it could be addressed with behavioral, as opposed to structural, mitigation measures.[90]

In the present matter, the Competitive Analysis Screen failures will, similarly, be temporary and, similarly, can be addressed with behavioral mitigation, as discussed above.

Moreover, similar to the transactions considered by the Commission in *Nevada Power* and *Osprey*, and more recently in *Tenaska Alabama*, imposing virtual or permanent divestiture would frustrate the purpose and intent of the Transaction for FPL. FPL seeks to acquire Vandolah in order to serve forecasted increases in load. Any mitigation that requires divestiture of generating capacity by FPL will leave FPL in the same position it started in—needing to acquire more generating capacity to serve load. Virtual or structural divestiture is thus not feasible here and, in fact, could prevent FPL from complying with its duties as a franchised retail utility under Florida law. And, when faced with similar facts by other utilities that needed generation to meet capacity needs to serve load,[91] the Commission did not require virtual or structural divestiture, and so should not require it here either.

c) FPL's "Must-Offer" Commitment is an Appropriate Behavioral Remedy to Any Temporary Adverse Competitive Effects That Result from the Transaction.

In view of these facts, and notwithstanding the reasons why it would be appropriate and consistent with precedent for the Commission not to require any mitigation in the first instance, in order to mitigate any temporary increase in market concentration that might arise from the Transaction, FPL is willing to undertake the below-described market-power mitigation measures,

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[90] *Nevada Power* at P 26 ("The Commission has generally considered structural remedies when a market power concern arises that is persistent over time and behavioral remedies or virtual divestitures when the market power concern is temporary, either due to short overlap before a facility retires or in the period after closing but prior to divestiture.") *See also id.* (describing and distinguishing structural, behavioral, and virtual mitigation).

[91] *See Osprey* and *Nevada Power*, cited *supra*; *Alabama Tenaska* at P 39.

should the Commission deem them necessary (the "Must-Offer Commitment"). As explained by Dr. Morris, behavioral mitigation in the form of the two-unit Must-Offer Commitment cures all screen failures in the FPL BAA in all price scenarios that otherwise result from the proposed Transaction.[92]

(1) The Mechanics of FPL's Must Offer Mitigation Proposal Are Consistent with *Nevada Power*

The specifics of the Must-Offer Commitment are set forth below, while the duration of the Must-Offer Commitment is discussed in the next section.

- **Quantity**. FPL will offer to the market, on a day-ahead basis, the energy output of at least two of the four Vandolah units (equivalent to 330 MW in the summer) during all Summer and Shoulder season hours (*i.e.*, "24/7", during peak and off-peak hours, March through November), to the extent this energy has not already been committed to a third party, such as through a bilateral forward sale.[93]

- **Product/Delivery Point**. The product offered would be unit-contingent "firm" energy delivered to the point of interconnection between Vandolah and FPL's transmission system, and would be recallable or cancellable only if there is an event of *force majeure* or other event that curtails the ability of FPL to generate and deliver such energy (such as a forced or unforced outage of one or more Vandolah units, fuel constraints, or a transmission constraint that results in dispatch curtailment).[94]

- **Pricing**. The offered price will not exceed the caps in FPL's cost-based wholesale power tariffs on file with the Commission.[95]

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[92] Morris Aff. at 33-34.

[93] Insofar as each Vandolah unit has certain operational limits (such as minimum loadings, minimum run, and minimum down times), FPL may impose certain conditions on the offers (such as minimum MW purchased or minimum hours purchased) consistent with such operational limits. Thus, to the extent that the sum of the requests for all prospective buyers the offered energy requires a unit to deliver energy below its minimum load capability, the buyers must increase or decrease their bid to a quantity that would satisfy the minimum load capability of the units, or else FPL would be permitted to deny the purchase request.

[94] No ancillary services such as Generation Control, Regulation, Frequency Response, or Voltage Support would be offered. The ancillary services associated with Vandolah must remain at the discretionary use of the FPL BAA operator in order to ensure system reliability.

[95] *See Florida Power & Light Co.*, 177 FERC ¶ 61,057 (2021) (accepting for filing eTariff submission of Tariff No. 1); *Florida Power & Light Co.*, Docket No. ER22-1805-000, Letter Order issued July 1, 2022 (accepting for filing transfer of tariffs from Gulf Power Company to FPL eTariff database).

- **Availability**. The Vandolah energy will not be offered if unavailable due to outage or the unavailability of fuel.[96] In addition, the Vandolah energy will not be offered if FPL reasonably anticipates that it will be needed to serve any native or wholesale load requirements (excluding any day-ahead and intraday non-firm sales), or to provide necessary reserve requirements. In this regard, FPL will not be required to sell Vandolah energy if doing so would require FPL to purchase energy from a third party to meet its needs or would trigger NERC Energy Emergency Alerts.[97] After it is lifted, a sale of energy from Vandolah pursuant to this Must-Offer Commitment will not be recalled absent a *force majeure* event.[98]

The Vandolah energy will be marketed and offered through the following process.

- **Bilateral Offer for Forward Term Sales**. To the extent that FPL determined that there will be periods for which Vandolah has a low likelihood of being needed to serve FPL system load, FPL will make Vandolah unit-contingent energy available on a bilateral basis for forward terms of less than one-year. Such offers and any subsequent sales will be made through normal bilateral channels (power purchase agreement, executed confirmation, recorded telephone, recorded instant message, or email) at or below the caps in FPL's cost-based wholesale power tariffs on file with the Commission.

- **Posted Offer for Day-Ahead Sales**. To the extent FPL has not forward-sold all of the Vandolah energy on a unit contingent basis and it is otherwise available (per above), FPL will offer the higher of 330 MW or the remaining unsold capacity according to the following process (and subject to the minimum load cap).

    - FPL will post, on a website, available Vandolah energy and the corresponding energy offer price on a business day-ahead basis (prior to 8:00 AM Eastern Prevailing Time ("EPT")), in two blocks depending on the time period:

        a. 16-hour On-Peak (7:00 AM to 11:00 PM EPT) and
        b. 8-hour Off-Peak (11:00 PM to 7:00 AM EPT).

    - In the event that any of the Must-Offer Capacity is not purchased in the market by 10:00 AM of each prior Business Day, the Vandolah energy will be released back to FPL for use at its discretion.

As explained by Dr. Morris, behavioral mitigation in the form of the two-unit Must-Offer Commitment cures all screen failures in the FPL BAA in all price scenarios that otherwise result

[96] Vandolah lacks firm gas transportation and, although it can also operate on oil, on-site oil storage is limited.

[97] *See Nevada Power Co.*, Docket No. EC16-130-001, Section 203 Market Power Mitigation Compliance Filing and Alternative Mitigation Proposal at 7-8 (Dec. 15, 2016).

[98] *Id.*

from the proposed Transaction.[99] More specifically, when 330 MW, the summer capacity of two of the four Vandolah units, are removed from FPL's "bucket" in the analysis, the HHI change resulting from the Transaction is zero points or less in each Summer and Shoulder period.[100]

The mitigation, however, does not cure the screen failures in the first-tier markets. But, as explained by Dr. Morris, "in these thinly traded markets, the DPT may produce misleading results."[101] In addition, "[b]ecause the transaction does not result in a reduction in competition in these markets, there is no competitive concern even in the absence of mitigation measures."[102] Thus, if and to the extent the Commission believes that horizontal market-power mitigation measures are needed, this proposed mitigation should alleviate any concerns the Commission may have.

The Must-Offer Commitment here is the same in all fundamental respects as that accepted by the Commission in *Nevada Power*—a unit-specific, must-offer commitment posted on an electronic bulletin board system[103] in sufficient quantity to mitigate any screen failures and until such time as HHIs are at the same level as they otherwise would have been absent the proposed transaction. The Commission should thus find it sufficient to mitigate any market power concerns resulting from the present proposed Transaction.

FPL also notes that it should suffice that the Must-Offer Commitment is only for the Summer and Shoulder seasons and not, in this regard, for the Winter season. As detailed by Dr. Morris, the Transaction results in screen failures in the FPL BAA under base prices only during

[99] Morris Aff. at 31-32.

[100] *Id.* at 32-33, Table 12; *see also id.* at Exh. JM-9.

[101] *Id.* at 33.

[102] *Id.* at 33.

[103] Whereas NV Energy proposed using an existing platform, if this Application is approved and conditioned on the Must-Offer Commitment, FPL will create a website.

the Summer Top 10% and Summer Top 1% periods and in the Shoulder season and other Summer periods when prices are increased 10 percent.[104] Mitigation is therefore only necessary during these periods, and is notably, not necessary in any winter periods.[105] The Commission has in the past found it sufficient for an entity that fails the Competitive Analysis Screens in only some periods to engage in mitigation measures only in those periods, and not in periods in which no screen failures occurred.[106] The same approach should be taken by the Commission here and, in this regard, the Commission should find that FPL need only adopt market power mitigation measures in the Summer and Shoulder seasons.

(2) FPL Proposes Must-Offer Commitment for a Duration Sufficient to Mitigate Any Temporary Competitive Effects

FPL offers this Must-Offer Commitment from the date of closing of the Transaction through May 31, 2030, which is a period that is three years from the expected closing date of the transaction and nearly five years from the date of this application. This duration is appropriate and has been established to continue as long as necessary to alleviate any market power concerns. As noted, the Commission has recognized that long-term capacity markets are competitive, provided that there are no barriers to entry (and there are no such barriers here).[107] And as explained in the Oliver Testimony, the time to construct a new solar paired with battery storage facilities in Florida is presently two to three years.

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[104] Morris Aff. at 8-9, Table 2.

[105] In fact, there is a strong argument that no mitigation is necessary in Summer Peak or Off-Peak or the Shoulder season because, insofar as these screen failures only occur when prices are increased by 10 percent they are not "persistent," and should therefore not be a cause for concern. *See supra* n. 79 and associated text. Still, if mitigation is necessary, FPL is willing to mitigate all Summer and Shoulder season periods.

[106] *See, e.g.*, *Nevada Power II* at 2 (mitigation in the form of must-offer requirement not to include summer 2018 and 2019); *Tucson Elec. Power Co.*, 156 FERC ¶ 61,170 at 19 (2016) (requiring mitigation during only winter peak period hours).

[107] *See supra* n. 86 and associated text.

Three years of behavioral mitigation should thus suffice here. Because competing solar generation and battery storage could, in response to the Transaction closing on June 1, 2027, come online prior to the summer of 2030,[108], there is no need to extend any behavioral mitigation measures past May 31, 2030.

In addition, market participants have an even longer "runway" because the present Application is being filed approximately two years before the closing of the Transaction. Thus, from the date of filing of this Application to the end of the proposed Must-Offer Commitment is nearly five years—well more than the time needed for competing solar and battery facilities to be constructed and reach commercial operation, and likely long enough for competing combustion turbines to be constructed.[109]

Notwithstanding the foregoing, should the Commission find it necessary, FPL is willing to extend its Must-Offer Commitment through December 31, 2031.[110] Extending mitigation through this date gives competitive entities more than enough time to construct solar facilities paired with batteries (or stand-alone batteries)—indeed, considerably more than the two to three years needed. It also gives such entities sufficient time to construct new combustion turbines which, as explained in the Oliver Testimony, presently takes three to five years to complete.[111]

In addition, as noted above, "but for" the proposed Transaction, FPL would have installed the Avoided Capacity by January 1, 2032. FPL will thus, with or without the present Transaction, have added to its system as of January 1, 2032, an amount of capacity roughly equivalent to that

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[108] *See* Oliver Testimony at 7-8 (stating that the average time from initiation to in-service date for a solar project is 32 months and BESS project is 22 months).

[109] *Id.* at 3.

[110] Insofar as the Must-Offer Commitment applies only to Summer and Shoulder periods, the commitment through December 31, 2031, will for all intents and purposes expire November 30, 2031, the end of the Shoulder season prior to December 31, 2031.

[111] Oliver Testimony at 11-12.

of Vandolah, making December 31, 2031, a logical outside date for any mitigation requirement as it represents a point in time when market concentrations would be expected, all else being equal, to approximate "but for" Transaction levels. In this case, the result is even better than that. Dr. Morris' analysis of the But-for Case, as noted above, confirms that adding the Avoided Capacity would result in market HHIs that are similar to or higher than those that result from the Transaction, as modeled in the Base Case.[112] It is thus entirely appropriate to allow any mitigation associated with the Transaction to sunset no later than December 31, 2031.

* * *

In all, while the proposed Transaction results in Competitive Analysis Screen failures under base prices in two summer periods, these failures are false positives that should not cause the Commission concern because they are a result of FPL's AEC increasing in an effort to meet the needs of growing load in a more cost-effective manner than constructing new generation. Nevertheless, if the Commission deems it necessary, FPL is willing to abide by the Must-Offer Commitment set forth above.

iii. Competitive Analysis Screen Results — Alternate Case

Dr. Morris' Alternate Case analysis shows no Competitive Analysis Screen failures in the DEF BAA but for a failure in the Shoulder Top 10% Period under Base Prices and +10% Prices.[113] In the FPL BAA, his Alternate Case analysis shows no screen failures, either under Base Prices or price sensitivity scenarios.[114] In markets first tier to the DEF BAA, his analysis shows isolated screen failures in the FMPP, GVL, and Tampa Electric Company ("TEC") BAAs.[115]

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[112] Morris Aff. at 15.

[113] *Id.* at 35-36.

[114] *Id.* at 37; *see also id.* Exh. JM-11 at 1, 3, 7.

[115] *Id.* at 34-37; *see also id.* Exh. JM-11.

In order to mitigate any horizontal market power concerns that might arise under this scenario (should the Vandolah Interconnection Line not be energized and capable of full-rating operation by June 1, 2027), FPL is willing to commit to the same mitigation as under the Base Case—a day-ahead, must-offer of the energy output of at least two of the four Vandolah units (equivalent to 330 MW in the summer) during at least all Summer and Shoulder season hours (to the extent this energy is not committed to a third party, such as through a monthly sale) from: (i) the later of the date of closing of the Transaction or June 1, 2027, until (ii) the date the new line is energized and Vandolah thus moves from the DEF BAA to the FPL BAA. The same terms and conditions of the Must-Offer Commitment detailed above, including the cost-based limitation on pricing, would apply here as well, except that the output of Vandolah would be offered at the generation bus in the DEF BAA instead of in the FPL BAA.

As explained by Dr. Morris, this transitory Must-Offer Commitment for the DEF BAA (should it be needed) would cure the screen failures, but for Summer Peak in TEC for the +10% price case and the Winter Top 10% in FMPP.[116] But, as with the Base Case analysis, this is a thinly traded market and the Transaction does not eliminate a competitor, and the screen failures after mitigation are isolated rather than systemic across markets and pricing scenarios. Thus, these isolated screen failures should not cause the Commission concern.

b. The Transaction Will Have No Adverse Effect on Horizontal Competition in Transmission

The Transaction will have no adverse effect on horizontal competition in transmission. As described above, FPL owns and controls electric transmission assets in Florida, but they are all subject to open access commitments and FPL's OATT on file with the Commission.[117] The

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[116] *Id.* at 16, 36-37; *see also id.* Exh. JM-12 at 1-3.

[117] The Vandolah Interconnection Line will be similarly subject to the FPL OATT.

Vandolah assets to be acquired by FPL, however, consist of no electric transmission assets, except for limited generator leads and step-up transformers that interconnect Vandolah to the DEF transmission system. The combination of FPL's transmission assets, with these limited generator interconnection facilities, should not give rise to concerns about the impact of the Transaction on horizontal competition in transmission. Thus, the Transaction will have no adverse effect on horizontal competition in transmission.

c. The Transaction Will Have No Adverse Effect on Vertical Competition

The Transaction will have no adverse effect on vertical competition. In Order No. 642, the Commission set forth guidelines to be used in determining whether a proposed transaction will have an adverse effect on vertical competition.[118] The Commission's concern with regard to vertical market power generally arises in circumstances, not present here, in which the combined entity may restrict potential downstream competitors' access to upstream supply markets or increase potential competitors' costs.

The consolidation of FPL's electric transmission assets with Vandolah will not enhance vertical market power because it will not enhance any ability of FPL or any of its affiliates to restrict potential downstream competitors' access to upstream supply. Indeed, as described above, access to FPL's transmission system is subject to the FPL OATT, and ownership of Vandolah will not provide FPL any enhanced ability to restrict potential downstream competitors' access to upstream supply. In prior proceedings, the Commission has found that open-access to transmission facilities provided sufficient assurance that the applicants could not use their control of

[118] Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,904-07.

transmission facilities in a manner that could harm competition.[119] The same conclusion should be reached here.

Accordingly, the Transaction will have no adverse effect on vertical competition.

d. The Transaction Will Not Create Barriers To Market Entry

In prior proceedings under FPA section 203, the Commission has considered whether a proposed transaction could enhance the applicants' ability to erect barriers to market entry in determining whether a proposed transaction may adversely impact competition.[120] The present Transaction will not provide FPL with any ability to erect barriers to market entry because it will not result in FPL acquiring any assets that could be used for such purposes. More specifically, Vandolah does not own or control, and FPL will not through the Transaction acquire, any vertical inputs to electric production, and Vandolah's limited and discrete interconnection facilities are not considered transmission assets subject to open-access requirements.[121] For example, the Transaction will not convey to FPL any control over upstream fuel assets that could be used to restrict electrical output of its competitors. Nor will it convey to FPL any sites for generation development, other than the limited land on which Vandolah presently sits. Further, FPL's transmission assets are subject to open access pursuant to FPL's OATT, as will be the new Vandolah Interconnection Line connecting Vandolah with FPL's grid. Accordingly, the Transaction will not create any barriers to market entry.

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[119] *See, e.g.*, *TECO Wholesale Generation, Inc.*, 107 FERC ¶ 62,208 (2004).

[120] *See, e.g.*, *Texas-New Mexico Power Co.*, 105 FERC ¶ 61,028 at PP 13-14 (2003); *PECO Energy Co.*, 90 FERC ¶ 61,269 at 61,903 (2000); *Boston Edison Co.*, 80 FERC ¶ 61,274 at 61,994 (1997).

[121] *See Vandolah Power Company, L.L.C.*, Docket No. ER10-2211-009, Triennial Market Power Analysis filed Dec. 22, 2023 (accepted by letter order dated May 15, 2025).

2. The Transaction Will Have No Adverse Effect on Rates

Under Order No. 642, the Commission must determine whether a proposed transaction will have any adverse impact on the rates charged to wholesale power and transmission customers.[122] The Commission focuses on whether a proposed transaction will have an effect on Commission-jurisdictional rates, whether the effect is adverse, and whether the adverse effect will be offset or mitigated by the proposed transaction's potential benefits.[123] The Commission has held that an acquiring utility's commitment to hold customers harmless from costs related to a proposed transaction over a five-year period of time after the transaction was sufficient to show that the proposed transaction would not have adverse effects on rates.[124] An applicant can alternatively recover transaction-related costs if they demonstrate offsetting benefits at the time they apply to recover the costs.[125]

The proposed Transaction will have no adverse effect on jurisdictional rates.[126]

Vandolah's Rates

Vandolah's entire power output is committed to DEF under the DEF Tolling Agreement through May 31, 2027. If and to the extent the Transaction closes before June 1, 2027, FPL will continue to honor this agreement through its stated termination date. The Transaction will thus have no adverse affect on the jurisdictional rates charged by Vandolah.

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[122] Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15; Order No. 592, FERC Stats. & Regs. ¶ 31,044 at 30,123.

[123] *See, e.g.*, *Osprey* at P 43.

[124] *Id.* at P 44.

[125] *Id.* at P 45.

[126] Indeed, the Transaction will have a beneficial effect on rates. As explained above and by Mr. Whitley, if FPL cannot acquire Vandolah, it will need to construct the Avoided Capacity. This will cost more than the present Transaction. The present Transaction will thus not only have no adverse effect on rates, it will have beneficial effect as compared to the alternatives available to FPL (that are otherwise unavoidable in view of the need for more generation to meet growing load).

FPL's Rates

FPL sells its wholesale energy under a variety of market-based and cost-based rates. The Commission has held that a transaction will not have an adverse effect on the wholesale rate of electricity when the wholesale customers' existing contracts were entered into under market-based rate authority.[127] The Commission has also held that when there are market-based rates, the effect of rates is not of concern "because market-based rates will not be affected by the seller's cost of service, and thus, will not be affected by the [transaction]."[128] Thus, there are no concerns about the Transaction having an adverse effect on FPL's market-based rate customers, none of which is within FPL's franchised service territory.

FPL also sells wholesale energy at cost-based rates through a combination of stated- and formula-rate agreements. Its customers under stated-rate agreements will not experience any adverse effect on their rates because, as a result of the stated-rate nature of their agreements, FPL has no ability to charge those customers any costs related to the Transaction or the costs of Vandolah itself, absent an FPA section 205 filing. The Commission has previously found that cost-based rate schedules provide no mechanism through which a transaction can be passed through to the rates absent a separate FPA section 205 filing, and thus, will be unaffected by the transaction.[129]

FPL sells wholesale energy to two customers at cost-based, formula rates—Florida Keys Electric Cooperative Association, Inc. ("Florida Keys") and Lee County Electric Cooperative, Inc.

[127] *See, e.g., Tucson Elec. Power Co.*, 169 FERC ¶ 61,204 at P 39 (2019) citing *Union Elec. Co.*, 114 FERC ¶ 61,255 at P 45 (2006); *NorAm Energy Servs., Inc.*, 80 FERC ¶ 61,120 at 61,382–83 (1997).

[128] *Cinergy Corp.*, 140 FERC ¶ 61,180 at P 41 (2012).

[129] *See, e.g., Calpine Corp.*, 162 FERC ¶ 61,148 at P 32 (2018).

("Lee County").[130] Absent a commitment otherwise by FPL, the costs of Vandolah would automatically flow through these formula rates into the costs charged under these agreements. And although the Commission has indicated that such cost inclusion may be permissible under the circumstances present here,[131] FPL commits not to include any costs of Vandolah in charges to Florida Keys and Lee County under these agreements absent Commission authorization to do so in response to a future FPA section 205 filing.

In addition, the Transaction will have no adverse effect on FPL's transmission service rates. The Transaction does not involve acquisition of any transmission assets, other than limited assets such as lead lines and step-up transformers, the value of which are not included in unbundled transmission rates.

Nonetheless, consistent with Commission policy and practice, FPL pledges generally to hold harmless all current unbundled electric transmission and wholesale energy customers from any costs associated with the Transaction (*i.e.*, transaction and transition costs) for a period of five years to the extent that such costs exceed savings related to the Transaction. Consistent with Commission precedent, "transaction costs" in this context includes all transaction-related costs, not only costs related to consummating the Transaction.[132] The Commission has found similar

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[130] *See* FPL Rate Schedule FERC No. 317, filed Oct. 20, 2021 in Docket No. ER22-158-000 (Lee County); FPL Rate Schedule FERC No. 322, filed Oct. 20, 2021 in Docket No. ER22-158-000 (Florida Keys).

[131] More particularly, the Commission has indicated that including such costs of an acquired, existing generating facility may be permissible where, as here, the plant is needed to "serve the acquiring company's customers or forecasted load within a public utility's existing footprint, in compliance with a resource planning process, or to meet specified NERC standards." *Policy Statement on Hold Harmless Commitments*, 155 FERC ¶ 61,189 at PP 5, 97 (2016).

[132] *See, e.g.*, *ITC Midwest LLC*, 142 FERC ¶ 62,106 at 64,243 (2013) (*citing PPL Corp. & E.ON U.S. LLC*, 133 FERC ¶ 61,083 at P 26 (2010)). This hold harmless commitment, however, is not a rate freeze and would not preclude changes in jurisdictional rates attributable to non-Transaction costs or to the costs or value of Vandolah itself as established in a proceeding under FPA section 205 or 206. The Commission has accepted similar limitations on this "hold harmless" commitment. *See ITC Midwest LLC*, Docket No. EC13-60-000, Application at n.14, filed Jan. 9, 2013. *See also PNM Res., Inc.*, 110 FERC ¶ 61,204 at P 43 (2005); *Ameren Corp.*, 108 FERC ¶ 61,094 at P 62 (2004); *Tucson Elec. Power Co.*, 103 FERC ¶ 62,100 at 64,163, n.3 (2003).

commitments by applicants under FPA section 203 sufficient to alleviate any concerns regarding the impact of a proposed transaction on FERC-jurisdictional transmission rates and, to the extent necessary, should do the same here.[133]

3. The Transaction Will Have No Adverse Effect on Regulation

Pursuant to Order No. 642, the Commission requires applicants to evaluate the effect of a merger or other proposed transaction on regulation both at federal and state levels. The Commission has indicated that it may set an FPA section 203 application for hearing if the affected state commission does not have authority to act on the proposed transaction and raises concerns about the effect on regulation.[134] In addition, while section 1263 of the Energy Policy Act of 2005 ("EPAct 2005") eliminated the need for the Commission to review the effect on regulation related to changes in control over a registered holding company under the Public Utility Holding Company Act of 1935, the Commission has stated that "applicants are still required to address whether the transaction will have any other effect on the Commission's regulation."[135] Neither of these concerns is raised by the Transaction, which will have no adverse effect on regulation.

The Transaction will not diminish federal regulatory authority over FPL or Vandolah. Following the Transaction, FPL (and its jurisdictional assets and wholesale power sales from Vandolah) will remain subject to the Commission's jurisdiction under the FPA. Accordingly, the Transaction will have no adverse effect on federal regulation.

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[133] *See, e.g.*, *Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261 at P 68 (2013); *Florida Power & Light Co.*, 145 FERC ¶ 61,018 at P 59 (2013).

[134] Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15.

[135] *Transactions Subject to FPA Section 203*, Order No. 669, FERC Stats. & Regs. ¶ 31,200 at P 196 n. 140 (2005) ("Order No. 669"), *order on reh'g*, Order No. 669-A, FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, 116 FERC ¶ 61,076 (2006).

Order No. 642 reflects the Commission's concern that state regulators should not be divested of authority to act on mergers of traditional, vertically-integrated utilities with captive retail (as well as wholesale) customers.[136] This concern is not applicable to the instant case because the Florida PSC's approval will be required prior to FPL including Vandolah in retail customer rates (although it is not required for consummation of the Transaction). Accordingly, the Transaction will have no adverse effect on state regulation.

B. The Transaction Will Not Result in Proscribed Cross-Subsidization or the Pledge or Encumbrance of Utility Assets

Under FPA section 203, as amended by EPAct 2005, the Commission will approve a proposed transaction:

> if it finds that the proposed transaction will be consistent with the public interest, and will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.[137]

As explained in Exhibit M, the Transaction satisfies this standard.

IV. THE COMMISSION'S PART 33 FILING REQUIREMENTS

In compliance with section 33.2 of the Commission's regulations, 18 C.F.R. § 33.2, Applicants submit the following information.

A. Section 33.2(a) — Exact Name of Applicant and its Principal Business Address

FPL's exact name is Florida Power & Light Company, and its principal place of business is 700 Universe Boulevard, Juno Beach, Florida 33408.

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[136] Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914-15.

[137] 16 U.S.C. § 824b(a)(4).

Vandolah Power's exact name is Vandolah Power Company LLC, and its principal place of business is 2394 Vandolah Road, Wauchula, Florida 33873.

B. Section 33.2(b) — The Names and Addresses of Persons Authorized to Receive Notices and Communications Regarding the Application

Applicants request that all notices, correspondence, and other communications concerning this Application be directed to the following persons.[138]

Jeffrey M. Jakubiak
Ankush J. Joshi
Vinson & Elkins LLP
1114 Avenue of the Americas, 32nd Floor
New York, NY 10036
(212) 237-0082
(202) 639-6692
jjakubiak@velaw.com
ajoshi@velaw.com

Justin Moeller
Assistant General Counsel
Florida Power & Light Company
801 Pennsylvania Avenue NW, Suite 220
Washington, DC 20004
(202) 349-3346
justin.moeller@fpl.com

Mark C. Williams
Day Pitney LLP
555 11th Street NW
Washington, DC 20004
(202) 218-3905
mwilliams@daypitney.com

C. Section 33.2(c) — Description of FPL (Exhibits A-F)

1. Business Activities (Exhibit A)

A description of Applicants and their business activities is included in Part I of this Application. In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit A.

2. Energy Subsidiaries and Energy Affiliates (Exhibit B)

FPL is an indirect, wholly owned subsidiary of NextEra, a multinational energy holding company with assets located throughout the United States as well as in various foreign countries.

[138] Applicants respectfully request waiver of the Commission's regulations in order to place more than two persons on the official service list for this proceeding.

It would be unduly burdensome to provide information here on all of FPL's affiliates. In addition, such information is by and large not relevant to the Commission's consideration of this Application. A description of FPL's energy affiliates operating in the Commission's Southeast MBR Region[139] is included in Exhibit B of this Application. (FPL has no energy subsidiaries.) FPL respectfully requests waiver of the need to provide additional information on its affiliates, as such information is not relevant to the Commission's consideration of this Application.

Vandolah Power has no energy subsidiaries and respectfully requests waiver of the need to provide any information regarding its affiliates. Insofar as these affiliates will not be acquired by FPL as part of the Transaction, information regarding them is not relevant to the Commission's consideration of this Application. Accordingly, Vandolah Power respectfully requests waiver of the need to provide any information in Exhibit B.

3. Organizational Charts (Exhibit C)

The organizational structures of FPL and its affiliates will not change as a result of the Transaction. Similarly, the only change to the organizational structure of Vandolah Power and its affiliates is that Vandolah Power will, as a result of the Transaction, cease to exist (after merging into FPL). In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit C.

4. Joint Ventures, Strategic Alliances, Tolling Arrangements or Other Business Arrangements (Exhibit D)

The Transaction will not create or result in any joint ventures, strategic alliances, tolling arrangements, or other business arrangements. With the exception of the Large Generator Interconnection Agreement between DEF and Vandolah Power (the "Vandolah LGIA"),[140] all

[139] *See* https://www.ferc.gov/power-sales-and-markets/electric-market-based-rates/triennial.

[140] The Vandolah LGIA, dated as of September 9, 2007, as amended and restated and entered into on November 1, 2019, was filed with the Commission on November 18, 2019 in Docket No. ER20-397-000 and accepted

Commission-jurisdictional contracts, joint ventures, or strategic alliances entered into by FPL will be honored after consummation of the Transaction, in accordance with their terms.[141] As regards the Vandolah LGIA, insofar as Vandolah Power will cease to exist as a result of the Transaction, the Vandolah LGIA will be assumed by FPL, stepping into the role of Vandolah as the interconnection customer.

In view of the foregoing, FPL respectfully requests waiver of the need to submit an Exhibit D.

5. Common Officers or Directors (Exhibit E)

FPL and Vandolah Power have no officers or directors in common. In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit E.

6. Wholesale Power Sales Customers and Unbundled Transmission Services Customers (Exhibit F)

The Transaction will not affect any service provided by FPL or by any affiliate to any wholesale power sales or unbundled transmission service customer. In addition, FPL reports all sales of wholesale power and unbundled transmission service in its Electric Quarterly Reports filed with the Commission.

Similarly, the Transaction will not affect any service provided by Vandolah or by any affiliate to any wholesale power sales customer. The DEF Tolling Agreement will expire on May 31, 2027, the day prior to the anticipated closing date of the Transaction. But this expiration would have occurred regardless of the Transaction and, thus, DEF, the customer under this agreement, is unaffected by the Transaction. If, however the Transaction closes before the DEF

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for filing, effective November 1, 2019, by Letter Order issued January 10, 2020. The Vandolah LGIA has a term that runs through October 1, 2032.

[141] *See Orion Power Holdings, Inc.* 98 FERC ¶ 61,136 at 61,396 (2002) (granting a waiver of the requirement to file Exhibit D based on the explanation that all contracts, joint ventures, and strategic alliances entered into before the Transaction will be honored after the merger).

Tolling Agreement expires by its terms on May 31, 2027, FPL will continue to honor the terms of the agreement through its stated expiration date.

In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit F.

D. Section 33.2(d) — Jurisdictional Facilities Owned, Operated, or Controlled by Applicant or Its Affiliates (Exhibit G)

The jurisdictional facilities owned, operated, or controlled by Applicants and their energy affiliates are described in Part I and Exhibit B. Additional information regarding jurisdictional facilities owned, operated, or controlled by FPL is set forth in its FERC Form 1s, the most recent of which was filed with the Commission on April 14, 2025. In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit G.

E. Section 33.2(e) — Jurisdictional Facilities and Securities Associated with or Affected by the Transaction, Consideration for the Transaction (Exhibit H)

The jurisdictional facilities, as that term is used in FPA section 203(a)(1), associated with or affected by the Transaction is the Vandolah facility (including associated transmission facilities such as generator lead lines and step-up transformers), its market-based rate tariff (which will be cancelled after the Transaction as a result of Vandolah Power ceasing to exist), the DEF Tolling Agreement (to the extent the Transaction closes before the agreement expires by its terms on May 31, 2027), and associated books and records. The consideration for the Transaction is set forth in the PSA (which is being filed confidentially). In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit H.

F. Section 33.2(f) — Contracts Related to the Transaction (Exhibit I)

Enclosed as Exhibit I is the PSA, for which Applicants request privileged treatment as set forth in Section VII, below. To the extent necessary, Applicants respectfully request waiver of the requirements of Section 33.2(f) of the Commission's regulations to the extent that they would require the filing of the exhibits and schedules to the PSA[142] and other incidental contracts and written instruments that may be entered into by the parties, none of which will be inconsistent with the PSA or the description of the Transaction set forth in this Application.

G. Section 33.2(g) — Facts Relied Upon to Show that the Transaction is Consistent with the Public Interest (Exhibit J)

A discussion of the facts relied upon to show that the Transaction is consistent with the public interest is provided above in Part III.A. In view of the foregoing, Applicants respectfully request waiver of the need to submit an Exhibit J.

H. Section 33.2(h) — Key Map Showing Properties of Each Party to the Transaction (Exhibit K)

Attached as Exhibit K is a map showing FPL and Vandolah Power's major energy assets.

I. Section 33.2(i) — Other Regulatory Approvals (Exhibit L)

Other than Commission acceptance of certain amended agreements, no other regulatory approvals are required for consummation of the Transaction. Appropriate notice will be provided, however, under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. In view of the foregoing information, Applicants respectfully request waiver of the need to submit an Exhibit L.

J. Section 33.2(j) — Cross-Subsidizations, Pledges or Encumbrances of Utility Assets (Exhibit M)

A discussion of cross-subsidization and related issues is set forth in Exhibit M hereto. In addition, a verification on behalf of FPL consistent with 18 C.F.R. § 33.2(j) and the guidance provided in Order No. 669 is attached as Appendix 1 hereto.[143]

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[142] *See, e.g.*, *Montenay Montgomery Ltd. P'ship*, 128 FERC ¶ 62,111 (2009) (granting FPA section 203 application based on application containing a copy of the transaction document from which the schedules and exhibits were omitted).

[143] *See* Order No. 669, FERC Stats. & Regs. ¶ 31,200 at P 169.

V. ADDITIONAL MATERIALS PROVIDED

A. Verifications

Verifications executed by Applicants' authorized representatives in accordance with 18 C.F.R. section 33.7 are provided in Appendix 1.

B. Proposed Accounting Entries

Pursuant to 18 C.F.R. section 33.5, proposed accounting entries for FPL related to the Transaction are provided in Appendix 5 hereto. As explained therein, FPL has included in these proposed accounting entries placeholders for the to-be-determined values and respectfully requests waiver of any need to provide actual values at this time. Rather, actual values will be submitted, in accordance with Commission precedent, within six months of consummation of the Transaction. The Commission has in the past found this approach sufficient and should make the same finding here.[144]

FPL notes that, consistent with Commission policy and precedent,[145] these proposed accounting entries reflect the recordation of any acquisition premium resulting from application of Electric Plant Instruction No. 5 to Account 114.

VI. REQUEST FOR ORDER BY DECEMBER 8, 2025

Applicants respectfully request that the Commission approve the Transaction no later than December 8, 2025. As discussed herein, FPL needs to add significant amounts of new capacity to meet forecasted increases in peak demand, and must know well in advance of the Transaction's

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[144] *See, e.g.*, *Tucson Elec. Power Co.*, Docket No. EC19-100-000, Application Pursuant to Federal Power Act Section 203 at 24, Appx. 3 (dated June 5, 2019) (providing proposed accounting entries with only placeholders rather than values).

[145] *See, e.g.*, *Ameren Corp.*, 140 FERC ¶ 61, 034 at P 30 (2012) ("The Commission has a long-standing policy related to the recovery of acquisition premiums, including goodwill, through rates. Under Commission policy, rate recovery of an existing facility is generally limited to the original cost of the facility and recovery of acquisition premiums including goodwill in cost-based rates is allowed only if the acquisition is prudent and provides measurable, demonstrable benefits to ratepayers.") (footnotes omitted).

June 1, 2027 closing date whether the Transaction will be approved or whether FPL should instead pursue development activities with respect to the Avoided Capacity.

VII. REQUEST FOR PRIVILEGED TREATMENT

Applicants respectfully request privileged treatment, in accordance with 18 C.F.R. section 388.112, for the PSA, submitted as Exhibit I. This agreement contains "[t]rade secrets and commercial or financial information obtained from a person [that are] privileged or confidential."[146] The information contained in this document is thus commercially sensitive and not publicly available. Accordingly, good cause exists for the Commission to grant this request for privileged treatment of this information.

As required by 18 C.F.R. sections 33.9 and 388.112(b), FPL has included as Appendix 6 hereto a proposed protective agreement based on the Commission's model protective order. Any questions regarding this request for confidential treatment should be directed to the following person:

Jeffrey M. Jakubiak
Vinson & Elkins LLP
1114 Avenue of the Americas, 32nd Floor
New York, NY 10036
(212) 237-0082
jjakubiak@velaw.com

[146] 18 C.F.R. § 388.107(d) & (f).

VIII. CONCLUSION

WHEREFORE, for the foregoing reasons, FPL respectfully requests that the Commission:

> approve the Transaction under FPA section 203 no later than December 8, 2025, without modification, condition, or a trial-type hearing.

Respectfully submitted,

/s/ Mark C. Williams
Mark C. Williams
Day Pitney LLP
555 11th Street NW
Washington, DC 20004
(202) 218-3905
mwilliams@daypitney.com

Attorney for Vandolah Power Company L.L.C.

/s/ Jeffrey M. Jakubiak
Jeffrey M. Jakubiak
Ankush J. Joshi
Vinson & Elkins LLP
1114 Avenue of the Americas, 32nd Floor
New York, NY 10036
(212) 237-0082
jjakubiak@velaw.com
ajoshi@velaw.com

Justin Moeller
Assistant General Counsel
Florida Power & Light Company
801 Pennsylvania Avenue NW, Suite 220
Washington, DC 20004
(202) 349-3346
justin.moeller@fpl.com

Attorneys for Florida Power & Light Company

Dated: June 10, 2025

APPENDIX 1

VERIFICATIONS

[See Attached]

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

VERIFICATION PURSUANT TO 18 C.F.R. § 33.7

I, Scott Bores, aver and state that: (i) I have authority to execute this Verification on behalf of Florida Power & Light Company, (ii) I have read the foregoing Application and attached Exhibits and know the contents thereof, and (iii) the same are true and correct to the best of my knowledge, information and belief.

Scott Bores
Vice President, Finance
Florida Power & Light Company

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.) **Docket No. EC25-___-000**

Florida Power & Light Company)

VERIFICATION-PURSUANT TO 18 C.F.R. §§ 33.7 AND 385.2005(b)

I, Jeffery W. Moore, am an authorized representative of Vandolah Power Company, L.L.C., including its affiliates (collectively "Applicant"), as the foregoing are defined in the attached application. I have read the foregoing application and have authority with respect thereto. I have knowledge of the factual matters regarding Applicant as set forth in the foregoing application, in my official but not personal capacity. The information set forth regarding Applicant and its affiliates set forth in the foregoing application is true and correct to the best of my present knowledge, information, and belief, and I submit this verification pursuant to 18 C.F.R. §§ 33.7 and 385.2005(c), consistent with and subject to 28 U.S.C. § 1746. I declare under penalty of perjury that the foregoing is true and correct.

Executed on this 6th, day of June, 2025.

By: Jeffery W. Moore
Name: Jeffery W. Moore
Title: Vice President

APPENDIX 2

TESTIMONY OF ANDREW WHITLEY

[See Attached]

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.	)	Docket No. EC25-___-000
Florida Power & Light Company	)	

PREPARED DIRECT TESTIMONY AND EXHIBITS

OF ANDREW W. WHITLEY

June 10, 2025

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.	)	Docket No. EC25-___-000
Florida Power & Light Company	)	

PREPARED DIRECT TESTIMONY
OF ANDREW W. WHITLEY

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Andrew W. Whitley. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Engineering Manager in the Integrated Resource Planning ("IRP") department of FPL's Finance Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. In my current position, I am responsible for the management and coordination of economic analyses that identify and evaluate resource alternatives to meet FPL's resource needs and to maintain system reliability. The analyses I oversee are designed to determine the magnitude and timing of resource needs for FPL's system and are used to develop the Company's integrated resource plan.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of FPL which, jointly with Vandolah Power Company L.L.C. ("Vandolah Power") (and collectively with FPL, the "Applicants"), is submitting an application seeking approval of the Federal Energy Regulatory Commission (the "Commission") under section 203 of the Federal Power Act ("FPA") of a proposed transaction pursuant to which FPL will (i) acquire Vandolah Power, the owner of the

660 MW (Summer) Vandolah Generating Facility ("Vandolah") and, immediately thereafter, (ii) merge Vandolah Power into FPL, resulting in FPL becoming the direct and sole owner of Vandolah (collectively, the "Transaction").

Q. What is your professional background and experience?

A. I graduated from Lehigh University in 2004 with a Bachelor of Science in Mechanical Engineering. I joined FPL in 2004 as part of the Power Delivery team, undertaking various engineering duties related to initiating new service to FPL customers and maintaining the reliability of customers' existing services. In 2007, I joined the team now known as the IRP group. Since that time, I have been involved in and supported a variety of resource planning projects for FPL, including FPL's Ten Year Site Plans ("TYSPs"), solar base rate adjustments, need determination proceedings for new power plants under the Florida Power Plant Siting Act (including the Okeechobee Clean Energy Center in 2015 and the Dania Beach Clean Energy Center in 2018), base rate proceedings, and the Demand-Side Management ("DSM") Goals proceedings. I became the Manager of the IRP group in 2022 and have served as the project leader for FPL's TYSPs since 2012.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I have submitted testimony to the Florida Public Service Commission ("Florida PSC") in numerous dockets, including DSM Goals proceedings, Solar Base Rate Adjustment proceedings, and FPL's 2025 Rate Case.

Q. Please summarize your testimony.

A. Part I of my testimony includes an introduction and describes my qualifications. Part II describes the purpose and scope of my testimony. Part III of my testimony describes FPL's need for additional capacity to serve forecasted load growth. Part IV of my testimony describes FPL's generation plan to serve forecasted load growth "but for" the Transaction. Finally, Part V describes FPL's alternative generation plan with Vandolah and my calculation of the customer savings associated with acquiring Vandolah.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe how FPL is planning resource additions and retirements to reliably serve the needs of FPL's customers over the next ten years. More particularly, I describe: (i) how FPL planned to meet its resource needs prior to entering into the Proposed Transaction to acquire Vandolah and (ii) how this will change if FPL acquires Vandolah in June 2027. In this regard, I also explain how FPL will no longer need some of the generation and battery storage capability that it would otherwise have added to its system but for the Transaction. As discussed herein, my analysis indicates that buying Vandolah will save FPL customers approximately $32 million on a cumulative present value of revenue requirements ("CPVRR") basis relative to FPL's generation plan "but for" the Transaction. These savings translate into projected lower system average electric rates for FPL's customers over the remaining life of the Vandolah facility.

Q. Are there any exhibits included with your testimony?

A. Yes. The following exhibits are included:

- Exhibit AWW-1: FPL's 2025 Ten Year Site Plan, and
- Exhibit AWW-2: Direct Testimony and Exhibits of Andrew Whitley in FPL's 2025 Rate Case.

III. FPL'S 2025 RESOURCE PLANNING PROCESS REVEALED THAT FPL REQUIRES ADDITIONAL GENERATION CAPACITY TO MAINTAIN RELIABILITY

Q. How does FPL determine its future demand and energy needs and how best to meet those needs?

A. There are three main goals of FPL's resource planning process:

1. Identify the timing of FPL's resource needs. The timing of future resource needs is largely determined by reliability standards, including planning reserve margin, generation-only reserve margin, and loss of load probability ("LOLP").
2. Identify the magnitude of these resource needs (*i.e.*, how many firm MW of capacity are needed to satisfy all reliability criteria).
3. Identify the type of resources, either supply-side or demand-side, that can meet the capacity needs while adding other resources that improve system economics. On an economic basis, this selection is determined by the option that is projected to result in the lowest electric rates for FPL's customers while satisfying all of FPL's reliability standards.

Q. Please provide an overview of FPL's resource planning process.

A. FPL's resource planning process can be summarized by the following four tasks:

- <u>Task 1</u>: Determine the magnitude and timing of FPL's new resource needs to maintain a reliable system.
- <u>Task 2</u>: Identify the resource options and resource plans that are available to meet the determined magnitude and timing of FPL's resource needs (*i.e.*, identify the available competing options and resource plans).

- Task 3: Evaluate the competing resource options and resource plans based on system economics and non-economic factors.
- Task 4: Select a resource plan to meet the identified needs.

Q. Is FPL experiencing load growth?

A. Yes. FPL's annual peak demand has grown from 25,361 MW in 2015 to 28,266 MW in 2024. FPL expects that trend to continue as more people and businesses relocate to the state of Florida in FPL's service area. FPL expects annual peak demand to increase to 31,677 MW by 2034.[1]

Q. What is driving FPL's projected load growth over this time period?

A. FPL's peak demand and energy growth through 2034 is primarily driven by customer growth. FPL's load forecast includes roughly 700 MW of projected peak load from data centers, which represents only a fraction of the 3,365 MW growth expected from 2025-2034.

Q. How does FPL ensure that it has sufficient generating capacity available to meet growing customer demand?

A. FPL uses three specific reliability criteria in projecting its future resource needs. The first criterion is a minimum total planning reserve margin ("PRM") of 20 percent for both summer and winter peak hours. The minimum 20 percent total PRM criterion was approved by the Florida PSC in Order No. PSC-99-2507-S-EU issued in Docket No. 981890-EU.[2]

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[1] *See* 2025 TYSP at 62 (Exh. AWW-1 at 75).

[2] https://www.floridapsc.com/pscfiles/library/filings/1999/15628-1999/15628-1999.pdf.

The second reliability criterion used by FPL is an LOLP criterion. LOLP is a projection of how well an electric utility system may be able to meet its firm demand (*i.e.*, a measure of how often firm load may exceed available resources). In contrast to a reserve margin approach that looks at the one summer peak hour and the one winter peak hour, the LOLP approach looks at the peak hourly demand for each day of the year. The LOLP approach takes into consideration the probability of individual generators being out-of-service due to scheduled maintenance or forced outages, the variability of load, the variability of production from intermittent generation resources, and the availability of duration-limited resources, such as battery storage and demand response programs. An LOLP analysis models each of these variables to generate a multitude of scenarios and the associated probability of a generation shortfall in these scenarios can be calculated. LOLP is typically expressed in terms of "numbers of times per year" that the system firm demand cannot be served. FPL's LOLP criterion is a maximum of 0.1 days per year, or one day in ten years. This LOLP criterion is commonly used throughout the electric utility industry and is consistent with North American Electric Reliability Corporation ("NERC") reliability planning standards.

The third reliability criterion used by FPL is a minimum generation-only reserve margin ("GRM") of 10 percent. The issue of having a sufficient generation component of the projected total reserve margin has been discussed annually in FPL's TYSP since 2011, and the GRM was adopted by FPL as a reliability criterion beginning in 2014. The GRM must be applied only after evaluating the amount of DSM in a resource plan.

Q. Has FPL expanded its reliability analysis to account for features that are specific to FPL's evolving system?

A. Yes. FPL's system has evolved over time such that the reliability analyses of the past do not sufficiently detect resource adequacy risks associated with FPL's generation profile. FPL's incorporation of cost-effective solar has increased and, as a result, the peak hour of the year—*i.e.*, the hour of greatest demand on the system—is no longer the most critical hour for determining reliability need. Now, the most critical time for capacity on FPL's system is at peak net demand, which occurs between 5:00 p.m. and 8:00 p.m., when solar facilities are providing less generation output. For these hours, as well as all other hours throughout the year, FPL needs to use additional, more modernized modeling analysis to determine its resource adequacy and identify where its greatest resource needs lie. Thus, for its 2025 resource planning, FPL added a stochastic LOLP analysis tailored to its system to identify: (1) hourly periods of the year where there is increased likelihood for a loss of load, and (2) available resources that can remediate the potential for that loss.

Q. How does stochastic LOLP modeling work?

A. Stochastic LOLP modeling incorporates vast amounts of data to develop a granular view of a utility's system adequacy in hour-by-hour segments. This modeling incorporates significantly more data in assessing system reliability than a traditional LOLP analysis, providing a substantially wider range of load and generation conditions across numerous scenarios. Through this analysis, a utility can more effectively determine the sufficiency of its hourly generation supply throughout the year, which, in turn, allows it to identify any needed system additions.

Q. What were the results of the stochastic LOLP analysis and how did FPL incorporate these results into its 2025 resource planning?

A. The stochastic analysis revealed that LOLP vulnerabilities will arise if FPL does not add considerable amounts of firm generation capacity to its system over the next ten years. Specifically, FPL needs 32,322 MW of firm capacity to be available in 2027 in order to maintain an LOLP of 0.1 days-per year in that year—and the required reliability need to reach the same 0.1 threshold increases to 34,102 MW in 2030, representing an increase of 1,780 MW.[3] By 2035, FPL's need for firm capacity will increase to 37,914 MW—representing an additional 3,812 MW that must be procured during that time.[4]

To address the resource need demonstrated through the stochastic analysis, FPL's resource planning process identified resources to timely address the need, as discussed in the next section of my testimony, while maintaining all reliability criteria, and tested the cost-effectiveness of the available resource options.

IV. FPL'S PLANNED GENERATION ADDITIONS FROM 2025 TO 2034 BUT FOR THE PROPOSED TRANSACTION

Q. How did FPL select resource additions to meet the need for new firm generation capacity in its 2025 TYSP?

A. FPL's resource selection process is guided by the Energy Exemplar AURORA planning model (the "AURORA model") and incorporates the stochastic LOLP modeling results that I detail above. The AURORA model is a software tool that utilizes sophisticated programming designed to simulate the economic dispatch of generation resources in an

[3] Exh. AWW-2 at 6, 15.

[4] *Id.* at 61.

electric system, helping to determine the most optimal mix of generation resources needed to meet future energy demand and maintain system reliability requirements. FPL has presented the Florida PSC with outputs from this model in numerous prior proceedings, and it was used to develop FPL's 2025 TYSP.

To develop a resource plan that is specific to FPL's needs, the AURORA model incorporates a number of forecasts and operating assumptions into its analysis including the following:

- The minimum 20 percent total Reserve Margin reliability criterion described earlier;
- Any additional resource needs from FPL's other reliability criteria;
- Forecasts for peak load, energy, fuel prices, and environmental compliance costs;
- Projections of future incremental DSM demand and energy additions, based on FPL's proposed DSM Plan;
- The existing capabilities of the units in the current FPL system, and any planned changes to those units; and
- Projections of fixed and variable costs, and the operating characteristics of a variety of generation options to meet FPL's resource needs in the future.

FPL ran the AURORA model with these assumptions to identify and test the cost-effectiveness of resource additions for inclusion in the 2025 TYSP. I reviewed the underlying assumptions and modeling methodology, and they are reasonable and consistent with how FPL has conducted forecasts for prior investments that have been approved by the Florida PSC.

Q. How does FPL determine the cost-effectiveness of its potential resource options?

A. FPL assesses the CPVRR of potential resource options to make this determination. CPVRR is a metric focused on total system economics and rate impacts and allows for a comparative evaluation of the cost-effectiveness of various resource options. FPL develops the CPVRR of different potential resource plans in a financial model that calculates FPL's time value of revenue requirements resulting from capital investments in future resource additions, as well as the operational and fuel cost projections of the FPL system under that resource plan, as estimated by the AURORA model. FPL assesses the CPVRR of competing resource alternatives by comparing the alternatives' abilities to economically meet an identical system load. This enables FPL to rank potential alternatives according to their respective impacts on both electricity rates and system revenue requirements. The CPVRR analysis therefore informs and furthers FPL's objective of minimizing its projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or "RIM" methodology), which is a tangible benefit to customers.

Q. How many potential resource plans did the AURORA model evaluate for FPL's system?

A. The AURORA model evaluated hundreds of possible resource plans that would meet FPL's future resource needs using only generation or supply options. These resource plans included consideration of all potentially implementable generation resources, including solar, battery storage, and fossil-fueled options. The AURORA model identified predominately utility-scale battery storage and solar resources as optimal additions based on their CPVRR relative to other resources and their ability to address input parameters specified for the model run.

Q. How did FPL review the AURORA model's outputs in light of the stochastic LOLP analysis findings?

A. FPL tested the resource additions identified by the AURORA model to determine the most cost-effective resources that could address FPL's reliability needs as identified through the stochastic LOLP analysis. This testing procedure was a necessary and additive component of the resource planning process, as the AURORA model identifies resource options on the basis of FPL's minimum reserve margin requirement, which is only analyzed at the system's summer and winter peaks (*i.e.*, two peak hours per year).

Q. What resource additions did FPL identify that most cost-effectively address the reliability needs identified through the stochastic LOLP analysis?

A. As summarized in Table ES-1 of FPL's 2025 TYSP,[5] FPL's resource planning identified the following installations as the most cost-effective to meet FPL's resource needs in the 2025 through 2034 timeframe:

- 894 MW_{AC} of solar in 2025;
- 1,419.5 MW_{AC} of battery energy storage systems ("BESS") storage and 894 MW_{AC} of solar in 2026;
- 819.5 MW_{AC} of BESS and 1,192 MW_{AC} of solar in 2027;
- 596 MW_{AC} of BESS and 1,490 MW_{AC} of solar in 2028;
- 596 MW_{AC} of BESS and 1,788 MW_{AC} of solar in 2029;
- 596 MW_{AC} of BESS and 2,235 MW_{AC} of solar in 2030;
- 596 MW_{AC} of BESS and 2,235 MW_{AC} of solar in 2031;
- 475 MW_{AC} 2x0 combustion turbines ("CTs") and 2,235 MW_{AC} of solar in 2032;

[5] 2025 TYSP at 16 (Exh. AWW-1 at 29).

- 1,192 MW_{AC} of BESS and 2,235 MW_{AC} of solar in 2033; and
- 1,267 MW_{AC} of BESS and 2,235 MW_{AC} of solar in 2034.

Note that all BESS additions listed above were specified to provide four hours of energy output at the stated capacity.

Q. Is it your assessment that the resource additions described above and in FPL's 2025 TYSP are the optimal system additions for FPL in years 2025 through 2034 if FPL does not acquire Vandolah as contemplated in the Transaction?

A. Yes. But for the Transaction, these are the most cost-effective system additions (as determined by lowest CPVRR) to meet FPL's reliability needs identified through the stochastic LOLP analysis and ensure sufficient capacity and generation production for every hour of the year. The resource additions identified in the 2025 TYSP,[6] which did not consider the proposed acquisition of Vandolah, are summarized in the table below:

[6] *See id.*

Year	Changes to Existing Generation MW additions / (subtractions)	New Generation Additions	Summer RM%
2025	18 MW CC Upgrades (12 MW) Pea Ridge	894 MW SoBRA	22.4
2026		521.5 MW BESS NWFL 894 MW Solar 1,419.5 MW BESS	24.1
2027	48 MW CC Upgrades (4 MW) Broward South	1,192 MW Solar 819.5 MW BESS	27.2
2028	14 MW CC Upgrades (32 MW) Lansing Smith 3A	1,490 MW Solar 596 MW BESS	26.6
2029	(150 MW) GCEC 4&5	1,788 MW Solar 596 MW BESS	26.3
2030	(3 MW) Perdido 1&2	2,235 MW Solar 596 MW BESS	25.8
2031		2,235 MW Solar 596 MW BESS	25.7
2032	(40 MW) Palm Beach SWA 1	2,235 MW Solar 2x0 CT (475 MW)	25.4
2033		2,235 MW Solar 1,192 MW Battery	25.5
2034		2,235 MW Solar 1,267 MW Battery	25.1
	Nameplate Solar Additions (2025-2034):	17,433 MW	
	Nameplate Storage Additions (2025-2034):	7,603 MW	

Note that all solar and battery storage additions are in nameplate MW.

V. THE ACQUISITION OF VANDOLAH IN JUNE 2027 WOULD REPRESENT A MORE COST-EFFECTIVE ALTERNATIVE TO THE GENERATION ADDITIONS INCLUDED IN FPL'S 2025 TYSP

Q. Describe Vandolah Power.

A. Vandolah Power is currently owned by Northern Star Generation LLC and began commercial operation on June 1, 2002. Vandolah Power's primary asset is a power plant facility that consists of four GE 7FA dual-fuel simple-cycle peaking units, with a total nameplate capacity of 660 MW (summer rating). It is located on approximately 41 acres in Wauchula, a city in Hardee County, Florida. Vandolah is electrically interconnected with Duke Energy Florida ("DEF") and situated within DEF's Balancing Authority Area ("BAA"). Retail electric service at the site is provided by Peace River Electric Cooperative. The facility supplies peaking energy and capacity to DEF under a tolling power purchase agreement, which is scheduled to expire on May 31, 2027.

Q. Describe the proposed acquisition of Vandolah Power from Northern Star Generation LLC.

A. If approved, the Transaction would become a central part of FPL's effort to expand its generation portfolio to meet its forecasted increase in resource needs in a manner that benefits its customers in terms of both reliability and cost. The Transaction will be consummated in accordance with the Purchase and Sale Agreement by and between Vandolah Holding and FPL dated April 9, 2025 (the "PSA"). More particularly, FPL will: (i) acquire Vandolah Power from Vandolah Holding and then immediately (ii) merge Vandolah Power into FPL, resulting in FPL becoming the direct and sole owner of the Vandolah facility. Applicants currently anticipate the Transaction being consummated on June 1, 2027.

Q. How does FPL plan to interconnect the project given that Vandolah is located in DEF's BAA?

A. FPL plans to build a new, approximately 14.5-mile 230 kV transmission line to tie the Vandolah facility directly to the FPL transmission system. The facility would then inject its output into a new FPL substation between the existing Gridiron and Vandolah substations, and Vandolah would be re-registered with NERC as a resource in the FPL BAA. The target transmission line in-service date is June 1, 2027, concurrent with the date of consummation of the Transaction.

Q. Did FPL evaluate the proposed acquisition of Vandolah and new transmission interconnection as a generation alternative in its 2025 TYSP analysis described above?

A. No. FPL did not execute the PSA to acquire Vandolah until April 9, 2025, after FPL's 2025 TYSP was submitted to the Florida PSC on April 1, 2025.

Q. Have you evaluated the acquisition of Vandolah as an alternative to some of the capacity additions identified in the 2025 TYSP?

A. Yes. Vandolah offers a lower cost and lower risk way to realize the 475 MW peaking combustion turbine capacity to be placed in-service on January 1, 2032, in the base case in the 2025 TYSP. The cost and lead times of turbine-based generation have significantly increased in the last year and continue to experience significant volatility. When FPL became aware of the opportunity to acquire Vandolah, it was evaluated as an alternative to the new build peaking units planned in 2032. The 660 MW Vandolah facility, however, has a 185 MW higher net capacity than the planned peaking units, which necessitated evaluation of what additional capacity resources could be deferred. The BESSs planned for 2027 were left as-is due to the small, but non-negligible risk that the Vandolah acquisition is terminated before its planned closing on June 1, 2027. Therefore, 400 MW of the four-hour BESSs planned to be placed in-service on January 1, 2028, having approximately the same firm capacity of the 195 MW additional capacity provided by Vandolah, were removed from the revised resource plan. This alternative resource plan, which replaced 400 MW of 2028 BESS and 475 MW of 2032 peaking units with the acquisition of Vandolah was evaluated using the same AURORA model used to evaluate the generation additions identified in the 2025 TYSP. The financial model, which incorporates these AURORA model results as well as the cost impacts of the planned new transmission line interconnecting Vandolah to the FPL system, yielded approximately $32 million CPVRR in savings compared to the original 2025 TYSP. The revisions to the 2025 TYSP that would result from FPL's acquisition of Vandolah are shown below.

Year	2025 TYSP[7]	Modified 2025 TYSP with Vandolah Transaction	Change
2025	894 MW_{AC} of solar	894 MW_{AC} of solar	None
2026	1,419.5 MW_{AC} of BESS 894 MW_{AC} of solar	1,419.5 MW_{AC} of BESS 894 MW_{AC} of solar	None
2027	819.5 MW_{AC} of BESS 1,192 MW_{AC} of solar	819.5 MW_{AC} of BESS 1,192 MW_{AC} of solar **660 MW_{AC} from Vandolah**	Addition of Vandolah
2028	596 MW_{AC} of BESS 1,490 MW_{AC} of solar	**196 MW_{AC} of BESS** 1,490 MW_{AC} of solar	400 MW reduction in BESS
2029	596 MW_{AC} of BESS 1,788 MW_{AC} of solar	596 MW_{AC} of BESS 1,788 MW_{AC} of solar	None
2030	596 MW_{AC} of BESS 2,235 MW_{AC} of solar	596 MW_{AC} of BESS 2,235 MW_{AC} of solar	None
2031	596 MW_{AC} of BESS 2,235 MW_{AC} of solar	596 MW_{AC} of BESS 2,235 MW_{AC} of solar	None
2032	2,235 MW_{AC} of solar 475 MW_{AC} 2x0 CTs	2,235 MW_{AC} of solar	No additional 475 MW of CTs
2033	1,192 MW_{AC} of BESS 2,235 MW_{AC} of solar	1,192 MW_{AC} of BESS 2,235 MW_{AC} of solar	None
2034	1,267 MW_{AC} of BESS 2,235 MW_{AC} of solar	1,267 MW_{AC} of BESS 2,235 MW_{AC} of solar	None

Q. Based on your analysis, is acquiring Vandolah a superior alternative to building 400 MW of BESS in 2028 and 475 MW of combustion turbines in 2032, as contemplated in the 2025 TYSP?

A. Yes. As mentioned above, this alternative resource plan yielded an estimated $32 million lower cost to FPL's customers. The combined capital and operating costs of the Vandolah facility, plus the cost of the new transmission line to integrate this resource into the FPL

[7] *Id.*

BAA, were $114 million lower cost on a present value basis than the future new-build BESS and peaking unit additions. These savings were partially offset by higher system fuel and variable operating costs resulting from the removal of the 400 MW of batteries, which would have been deployed in a way to reduce unit cycling and displace lower efficiency generation resources.

Cost Component	**CPVRR**
Vandolah Acquisition	$488 million
New Transmission Line	$156 million
System Fixed Cost Impacts	($758) million
System Variable Cost Impacts	$82 million
Total Revenue Requirements	**($32) million**

In short, the acquisition of Vandolah gives FPL a faster, more cost-effective, lower-risk way to meet a real and growing need in FPL's service area. The savings calculated above were estimated earlier this year and are a conservative estimate as the estimated cost of new combustion turbine power plants has continued to rise. The purchase is not speculative—it's tied directly to identified system need. It eliminates the uncertainty around the permitting, siting, and procurement process for new capacity additions, particularly for the planned combustion turbines. And it avoids passing through those development risks and costs to FPL's retail customers. In every way—cost, timing, reliability, and planning certainty—this transaction is in the public interest.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT AWW-1

FPL'S 2025 TEN YEAR SITE PLAN

[See Attached]

William P. Cox
Senior Counsel
Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
(561) 304-5662
(561) 691-7135 (Facsimile)
E-mail: will.p.cox@fpl.com

April 1, 2025

-VIA ELECTRONIC FILING-

Adam Teitzman
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20250000-OT
Florida Power & Light Company's 2025 – 2034 Ten Year Power Plant Site Plan

Dear Mr. Teitzman:

Please find enclosed for electronic filing Florida Power & Light Company's 2025 – 2034 Ten Year Power Plant Site Plan. Per Commission Staff's request, five (5) hard copies will also be provided to your office.

Please contact me if you have any questions regarding this submission.

Sincerely,

s/ William P. Cox
William P. Cox
Senior Counsel
Florida Bar No. 0093531

WPC:cw
Enclosures

Ten Year Power Plant Site Plan
2025 – 2034

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Ten Year Power Plant Site Plan

2025-2034

Submitted To:

**Florida Public
Service Commission**

April 2025

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Table of Contents

List of Figures, Tables, and Maps

List of Schedules

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Overview of the Document

Chapter 186, Florida Statutes, requires that each electric utility in the State of Florida with a minimum existing generating capacity of 250 megawatts (MW) must annually submit a Ten-Year Power Plant Site Plan (Site Plan). This Site Plan should include an estimate of the utility's future electric power generating needs, a projection of how these estimated generating needs could be met, and disclosure of information pertaining to the utility's Preferred and Potential power plant sites. The information contained in this Site Plan is compiled and presented in accordance with Rules 25-22.070, 25-22.071, and 25-22.072, Florida Administrative Code (F.A.C.).

Site Plans are long-term planning documents and should be viewed in this context. A Site Plan contains uncertain forecasts and tentative planning information. Forecasts evolve, and all planning information is subject to change, at the discretion of the utility. Much of the data submitted is preliminary in nature and is presented in a general manner. Specific and detailed data will be submitted as part of the Florida site certification process, or through other proceedings and filings, at the appropriate time.

This Site Plan document addresses Florida Power & Light Company (FPL), which includes the service area of the former Gulf Power Company (Gulf). NextEra Energy, Inc. (NextEra Energy), the parent company of FPL, acquired Gulf in January 2019. Resource planning is now being done for the single entity of FPL, with Gulf's former service area now referred to as FPL's Northwest Florida Division (FPL NWFL). The information presented in this Site Plan is based on integrated resource planning (IRP) analyses that were carried out in 2024 and the 1st Quarter of 2025. The forecasted information presented in this plan addresses the years 2025 through 2034.

This document is organized in the following manner:

Chapter I – Description of Existing Resources

This chapter provides an overview of FPL's current generating facilities. Also included is information on other FPL resources including purchased power, demand-side management (DSM), and FPL's transmission system.

Chapter II – Forecast of Electric Power Demand

The load forecasting methodology utilized for FPL, and the resulting forecast of seasonal peaks and annual energy usage, are presented in Chapter II. Included in this discussion is the projected significant impact of federal and state energy efficiency codes and standards.

Chapter III – Projection of Incremental Resource Additions

This chapter discusses the IRP process and presents currently projected resource additions for FPL. This chapter also discusses a number of factors or issues that either have changed, or may change, the resource plan presented in this Site Plan. Furthermore, this chapter also discusses previous and planned DSM efforts, the projected significant impact of state/federal energy efficiency codes and standards, previous and planned renewable energy efforts, projected transmission additions, and the fuel cost forecasting processes.

Chapter IV – Environmental and Land Use Information

This chapter discusses environmental information as well as Preferred and Potential Site locations for additional electric generation facilities for FPL.

Site descriptions and site maps for Preferred and Potential sites are located in the Appendix.

Chapter V – Other Planning Assumptions and Information

This chapter addresses twelve (12) “discussion items” which pertain to additional information that is included in a Site Plan filing.

Appendix – Site Descriptions and Site Maps for Preferred and Potential Sites.

The appendix includes all site descriptions and maps for the Preferred and Potential Sites that were included in Chapter IV.

FPL
List of Abbreviations
Used in Forms

Reference	***Abbreviation***	***Definition***
Unit Type	BS	Battery Storage
	CC	Combined Cycle
	CT	Combustion Turbine
	GT	Gas Turbine
	PV	Photovoltaic
	ST	Steam Unit (Fossil or Nuclear)
	IC	Internal Combustion
Fuel Type	BIT	Bituminous Coal
	FO2	#1, #2 or Kerosene Oil (Distillate)
	FO6	#4,#5,#6 Oil (Heavy)
	N/A	Not Applicable
	NG	Natural Gas
	No	None
	NUC	Uranium
	Pet	Petroleum Coke
	Solar	Solar Energy
	SUB	Sub Bituminous Coal
	ULSD	Ultra - Low Sulfur Distillate
Fuel Transportation	N/A	Not Applicable
	No	None
	PL	Pipeline
	RR	Railroad
	TK	Truck
	WA	Water
Unit/Site Status	L	Regulatory approval pending. Not under construction
	OP	Operating Unit
	OT	Other
	P	Planned Unit
	RT	Retired
	T	Regulatory approval received but not under construction
	U	Under construction, less than or equal to 50% Complete
	V	Under construction, more than 50% Complete
Other	ESP	Electrostatic Precipitators
	k-Factor	The k-factor for the capital costs of a given unit is the cumulative present value of revenue requirements (CPVRR) divided by the total installed cost
	ST	Solar Together
	SoBRA	Solar Rate Base Adjustment

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Executive Summary

This Site Plan addresses the projected electric power generating resource additions and retirements for the years 2025 through 2034 for FPL.

I. Background / Overview of FPL's 2025 Site Plan

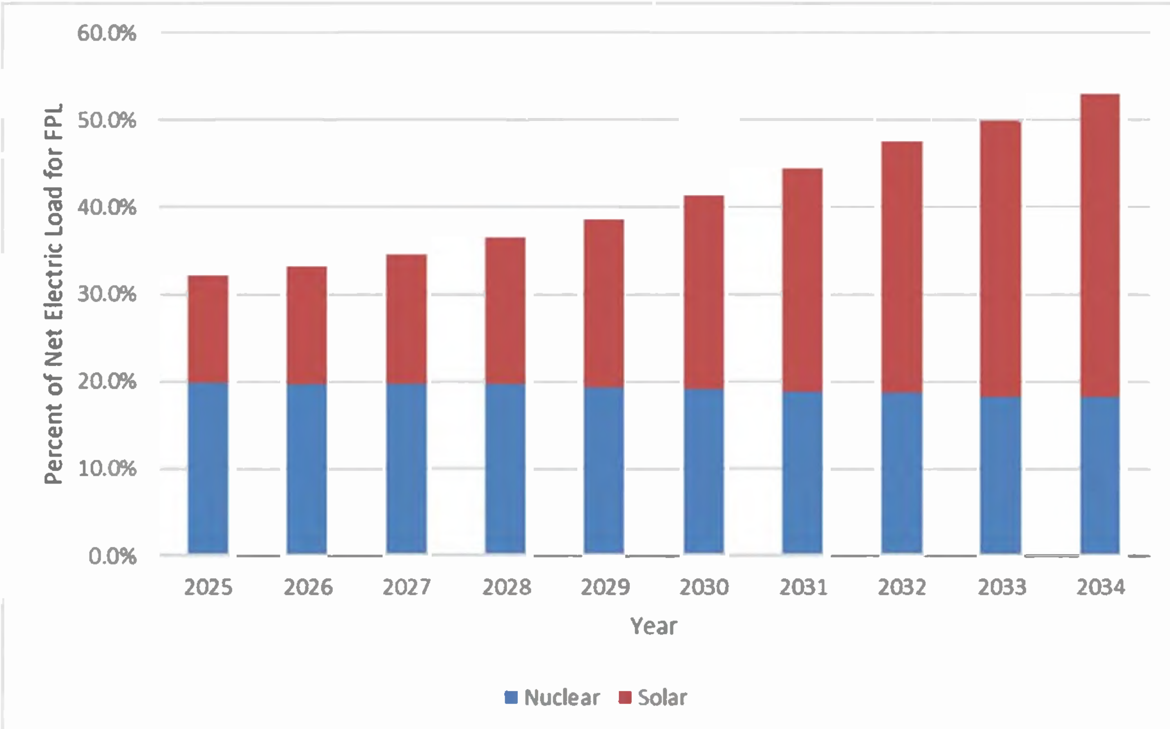
This 2025 Site Plan presents the current plans to augment and enhance the electric generation capability of the FPL system to meet projected incremental resource needs for a reliable and economic electric system for 2025 through 2034. As customers continue to move into FPL's service area and extreme weather events occur with more frequency, it is more important than ever that FPL has sufficient resources to meet continued growth, maintain adequate reserves, and provide reliable energy at all times. In order to meet these needs economically, FPL is planning on the following actions during the ten-year reporting period of this document:

1) Install 17,433 MW of cost-effective, solar generation - These solar additions will generate reliable energy using no fuel, which mitigates the commodity price risk to customers, enhances fuel diversity and helps secure Florida's energy independence.
2) Install 7,603 MW of battery storage – As a complement to FPL's planned solar additions, FPL is planning to deploy 7,603 MW of battery storage, which provides cost-effective capacity, regardless of the time of day or the weather conditions. These additions enable solar energy produced during the day to be stored and delivered even when the sun is not shining. Storage acts as a key resource that improves system reliability and resource adequacy by addressing the evening peak cost-effectively.
3) Develop natural gas capacity for a potential in-service date of 2032 – Solar and battery storage remain the most-cost effective resource options as well as the only viable options to meet FPL's needs in the near-term. However, long-term trends of load growth require FPL to continually examine other options to provide resource adequacy to its customers when they need it the most. Consequently, FPL projects 475 MW of combustion turbine (CT) capacity coming online in 2032.

As FPL's system continues to incorporate additional cost-effective solar generation, the Company is continuing to adapt its resource planning to meet customers' reliability needs through available, dispatchable resources that provide value to customers. Just as FPL's system has advanced and modernized over time to incorporate a wide variety of resource options, resource adequacy must also be modernized to consider conditions that affect the delivery of power in times of greatest need. FPL's proposed resource additions in this plan are a result of a comprehensive, stochastic loss of load probability (LOLP) analysis designed so that FPL's proposed system additions optimally address system needs for each hour of the year. This enhancement of an existing reliability criterion factors in variations in system load, generating unit outages, and solar performance results in a resource plan that provides reliability for customers throughout the year in a variety of system conditions.

Regarding FPL's fuel mix, FPL delivered approximately 28% of its energy from nuclear and solar generation during 2024. Nearly all the remainder of FPL's energy generation in 2024 came from natural gas. By 2034, the last year of the ten-year reporting period addressed in this document, the percentage of the total energy delivered to all customers on FPL's system from nuclear and solar generation is projected to be approximately 53%. New cost-effective solar will also provide fuel diversity and energy independence by reducing the amount of natural gas FPL will use to generate electricity compared to the present day and adding battery storage will provide cost-effective capacity to help maintain system reliability. This diversity will also help to act as a hedge against swings in natural gas price volatility, providing additional savings to FPL customers during these periods. The graph below in Figure ES-1 represents a ten-year projection for the years 2025 through 2034 of the percentage of FPL's total generation (GWh) consisting of nuclear and solar, a result of FPL's commitment to building the lowest cost generation for customers. Further details regarding projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 in Chapter III.

Figure ES-1: Nuclear and Solar Energy as a Percentage of Net Electric Load



By design, the primary focus of this document is on projected supply side additions, *i.e.*, electric generation capability and the sites for these additions. The supply side additions discussed herein are resources projected to be needed after accounting for existing and projected demand-side management (DSM) resources (including demand response and energy efficiency). In April of 2024, FPL filed its DSM Goals for the period of 2025 through 2034, and these Goals were approved by the FPSC on December 3, 2024. These DSM Goals address demand-side activities that reduce system peak loads and annual energy usage, along with consideration of the impacts of DSM on electric rates under which all customers are served. DSM is discussed in more detail in Chapters I, II, and III.

Additionally, FPL's load forecast accounts for a very large amount of energy efficiency that results from federal and state energy efficiency codes and standards. The projected impacts of these energy efficiency codes and standards are discussed later in this Executive Summary and in Chapters II and III. The updated load forecast presented in this Site Plan also accounts for the projected impact of both private rooftop photovoltaic (PV) solar and electric vehicle (EV) adoption.

FPL's projected resource additions and retirements over the ten-year reporting period are summarized below in Section II of this Executive Summary. In addition, there are several factors that either have influenced, or may influence, ongoing resource planning efforts. These factors could result in different resources being added in the future than those presented in this document. These factors are discussed in Section III of this Executive Summary. Additional information regarding these topics is presented later in this document in Chapter III.

II. Summary of Projected Changes in Resources:

A summary of the projected resources, including additions and retirements, is presented below. This discussion is presented in terms of the various types of resource options (such as solar and battery storage) in the resource plan.

Solar:

At the end of 2024, FPL had a total of approximately 7,038 MW[1] of utility-owned solar generation, all of which are PV facilities. These solar sites are located throughout FPL's service area.

The resource plan presented in this Site Plan continues to show significant increases in solar PV resources over the ten-year reporting period. Approximately 17,433 MW of additional, cost-effective PV generation is projected to be added in the 2025 through 2034 time period. These solar MW consist of solar facilities that are projected to be 74.5 MW each. When combining these projected additional solar facilities with the approximately 7,038 MW of solar PV already installed on FPL's system at the end of 2024, FPL's projected total of solar PV by the end of 2034 is 24,471 MW.

FPL received cost recovery approval for the 2025 solar additions in this year's resource plan pursuant to the Solar Base Rate Adjustment (SoBRA) provisions in the 2021 Settlement Agreement[2]. FPL's solar additions in 2026 through 2029 are consistent with FPL's petition for a base rate adjustment filed on February 28, 2025. The other solar additions shown in this Site Plan for the years 2030 through 2034 are based on an expectation that these solar additions will also be shown to be cost-effective. FPL's resource planning work in 2025 and beyond will continue to analyze the projected system economics of these later solar additions. FPL will seek Florida Public Service Commission (FPSC) approval for cost recovery of these later solar additions at appropriate times as has been FPL's practice with previous solar additions.

[1] Each reference to PV capacity throughout this Site Plan reflects the nameplate rating, Alternating Current (AC), unless noted otherwise.
[2] The 2025 SoBRA additions were approved by the FPSC in 2024

Battery Storage:

Currently, FPL has 469 MW of large-scale, grid-connected battery storage installed on its system at three separate locations. The first of these locations is a battery storage facility with a projected maximum output of 409 MW that was placed in-service at the existing Manatee plant site. This large battery storage facility is charged by solar energy from an existing nearby PV facility. Another 60 MW of battery storage, consisting of two 30 MW battery storage facilities installed at the Echo River and Sunshine Gateway solar centers in the FPL service area, were also placed into service at the end of 2021. Both of these 30 MW battery storage facilities are also charged by existing solar facilities.

For new storage facilities, FPL plans on adding 521.5 MW of battery storage at the end of 2025. FPL's battery storage additions in 2026 through 2029 totaling 3,431 MW are consistent with FPL's petition for a base rate adjustment filed on February 28, 2025. For the 2030 through 2034 time period, FPL plans on adding 3,651 MW of battery storage. In total, FPL's resource plan presented in this Site Plan projects that an additional 7,603 MW (nameplate) of battery storage facilities will be installed by 2034, which results in a total of 8,072 MW by the end of 2034. These battery storage facilities will primarily be sited adjacent to solar throughout FPL's service area. These additions will both improve overall system reliability and increase operational versatility by allowing batteries to be charged by the lowest cost resource available.

In addition to the large-scale batteries that FPL factors into its resource planning analyses, FPL's system also includes several smaller-scale batteries that provide varied services to FPL's system. These batteries are discussed further in Chapter III.

Development of Potential New Combustion Turbine Generation:

In the near term, solar and battery storage continue to be the most cost-effective and only available resource options for FPL customers. However, long-term trends of load growth require FPL to examine other options to provide resource adequacy to its customers when they need it the most. Consequently, FPL projects 475 MW of CT capacity coming online in 2032.

Modernization of FPL's Fossil-Fueled Generation:

For several years, FPL has undertaken a variety of efforts to modernize its fossil-fueled generation fleet based on cost-effectiveness. These efforts have resulted in substantial enhancements to the fleet of generating units, including improved system fuel efficiency and increased capacity, reduced system air emission rates, and dramatically reduced fuel-related costs for FPL customers. FPL plans to continue these efforts and to further improve the efficiency and capabilities of FPL's generation fleet through two principal initiatives: (i) retirement of existing generating units that are no longer economic to operate and

(ii) enhancements to existing generating units. These modernization efforts are separately described below.

(i) <u>Retirement of Existing Generating Units That Are No Longer Economic to Operate:</u>

The resource plan for the 2025 TYSP reflects the retirements of two units: Gulf Clean Energy Center Units 4 & 5. These units will be retired at the end of 2029. In the 2024 TYSP, FPL had previously reflected the retirement of its 25% ownership share (215 MW) in the coal-fueled Scherer Unit 3 in Georgia at the end of 2028. Because the primary owner of Unit 3, Georgia Power, amended its retirement date for Scherer Unit 3, FPL has had to follow suit and push out its retirement date for its interest in that unit to outside of the ten-year period of this Site Plan.

(ii) <u>Enhancements to Existing Generating Units:</u>

In previous Site Plans, FPL discussed plans to upgrade the CT components in a number of FPL's existing CC units to continue to add additional summer capacity and improve the overall fuel efficiency of the fleet. These upgrade efforts remain a part of FPL's resource planning. Information regarding the specific units, timing, and magnitude of these upgrades is presented in Schedule 8 in Chapter III.

<u>Nuclear energy:</u>

Nuclear energy remains an important factor in FPL's resource planning due to its combination of low fuel cost, around-the-clock operation, and location close to major load centers. FPL's current nuclear fleet consists of four nuclear units located at two sites within its service area. In total, these sites provide approximately 3,500 MW of summer capacity and in 2024, provided 28,009 GWh of energy to FPL's system. This amount of energy represented roughly 19% of FPL's generation in 2024. In order for these units continue to provide around-the-clock energy to FPL's customers, FPL secured Subsequent License Renewals (SLR) for both units at Turkey Point and is in the process of securing SLRs for both units at St. Lucie. More detailed information on these re-licensing efforts is available in Chapter III. For purposes of this Site Plan, FPL's resource planning analyses have assumed the continued operation of Turkey Point Units 3 & 4 through 2052 and 2053, respectively and St. Lucie Units 1 & 2 through 2056 and 2063, respectively.

Regarding potential future nuclear additions, in June 2009, FPL began the process of securing Combined Operating Licenses (COL) from the federal Nuclear Regulatory Commission (NRC) for two future nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (the location of two existing nuclear generating units). In April 2018, FPL received NRC approval for these two COLs, and these licenses currently remain valid with the earliest possible in-service dates for Turkey Point 6 & 7 beyond the ten-year period addressed in this 2025 Site Plan. FPL is also continuing to monitor advanced nuclear power options such as small modular reactors (SMR). Should SMR plants become a commercially viable technology in the future, FPL is planning to begin the initial stages of Early Site Permitting in 2026-2027 timeframe, available under NRC rules, for a potential SMR at a site that is adjacent to an existing nuclear power plant. This strategic move is aimed at minimizing risks, allowing emerging technologies to mature, and enabling robust and well-developed regulatory frameworks prior to deployment, while remaining cognizant of the current high costs of nuclear and SMR development and taking a stepwise approach. FPL is closely monitoring current initiatives at both the Department of Energy and the NRC. By taking these steps early on, FPL aims to be well-positioned to benefit from potential state and federal incentives for future nuclear deployment. The projected in-service date of an SMR would be outside the ten-year period addressed in this Site Plan.

III. Other Factors That Have Influenced, or Could Further Influence, FPL's Resource Planning Work:

There are a number of factors that have influenced, or which may influence, FPL's resource planning work. These ten other factors are summarized below. These additional factors are presented in no particular order, and their potential influences on FPL's resource planning work are further discussed in Chapters II and III.

<u>Factor # 1: Continued Impacts of Tax Credits for Batteries and Solar.</u> FPL's resource planning work continues to factor in tax credits for new utility-owned batteries and solar. For new utility owned standalone batteries, the 30% Investment Tax Credit (ITC) effectively lowers the capital cost for a new battery, with the potential of an additional 10% if the battery is located in a specific area. For new utility-owned solar, a utility can elect a Production Tax Credit (PTC) for new solar that is based on the amount of energy (MWh) the new solar facility generates each year for the first ten years of operation. For future resource additions, the PTC rate in 2025 starts at $30 for each MWh generated.[3] The $30 per MWh credit amount for a new solar facility that comes in-service increases with inflation each year. FPL's resource plan presented in this Site Plan accounts for the effects of these tax credits.

<u>Factor # 2: The critical need to maintain a balance between load and generating capacity in specific regions of FPL's service area, such as in Northwest Florida and Southeastern Florida (Miami-Dade and</u>

[3] To give an idea of the magnitude of the impact of the solar PTC, consider a simple example of a 75 MW solar facility that produces approximately 150,000 MWh per year in 2025 (*i.e.*, if assuming a net capacity factor of 23%). The proposed solar PTC for that year would result in a tax credit of (150,000 MWh x $30/MWh =) $4.5 million. This first year tax credit would then be extended for nine more years while being adjusted for inflation.

Broward counties). This balance has both reliability and economic implications for FPL's system and customers, and it is a key reason that FPL has expanded generation and transmission in specific areas in the past. The battery storage units that FPL is adding throughout the ten-year period will aid in addressing these balance concerns.

Factor # 3: The desire to maintain/enhance fuel diversity in the FPL system while considering system economics and reliability. Diversity is sought in terms of the types of fuel that FPL utilizes and how these fuels are transported to the locations of FPL's generation units. These fuel diversity objectives are considered in light of economic impacts to FPL's customers. For example, FPL is projecting the addition of significant amounts of cost-effective PV generation throughout the ten-year reporting period of this document. These PV additions enhance fuel diversity while at the same time allowing for the lowest cost generation resource to be constructed and operated. To enhance the reliability of these PV solar additions, FPL is planning to add cost-effective battery storage to maintain adequate generation and reserves at the time of the net system peak (FPL's peak after accounting for solar generation). At the same time, FPL is continuing to retire generating units that are no longer cost-effective for FPL customers. In addition, FPL also seeks to: 1) further enhance the efficiency with which it uses natural gas to generate electricity, 2) maintain the ability to use backup distillate oil that is stored on-site at many of FPL's gas-fueled generating units for purposes of system reliability, and 3) examine the ability of existing units to run on alternative clean fuels, such as hydrogen and renewable natural gas. All of the aforementioned additions enhance the overall fuel diversity of FPL's system which increases the energy independence of FPL's customers in the State of Florida.

Factor # 4: The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations. FPL addresses this through the use of a 10% generation-only reserve margin (GRM) reliability criterion to complement its other two reliability criteria: a 20%[4] total reserve margin criterion for Summer and Winter, and an annual 0.1 day/year LOLP criterion. Together, these three criteria allow FPL to address this specific concern regarding system reliability and operations in a comprehensive manner.

Factor # 5: The significant impact of federal and state energy efficiency codes and standards. The incremental impacts of these energy efficiency codes and standards are projected to have significant impacts by reducing forecasted Summer and Winter peak loads, and by reducing annual net energy for

[4] The 20% reserve margin requirement is a minimum requirement – FPL's projected reserve margin may be higher than 20% during some years as additional resources are added for resource needs and meeting other reliability criteria.

load (NEL), in FPL's system. From the end of 2024 through the year 2034, these energy efficiency codes and standards are projected to reduce Summer peak load by approximately 2,000 MW, reduce Winter peak load by approximately 520 MW, and reduce annual energy usage by approximately 2,460 GWh. In addition, energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs. The projected impacts of these energy efficiency codes and standards are discussed in more detail in Chapter II.

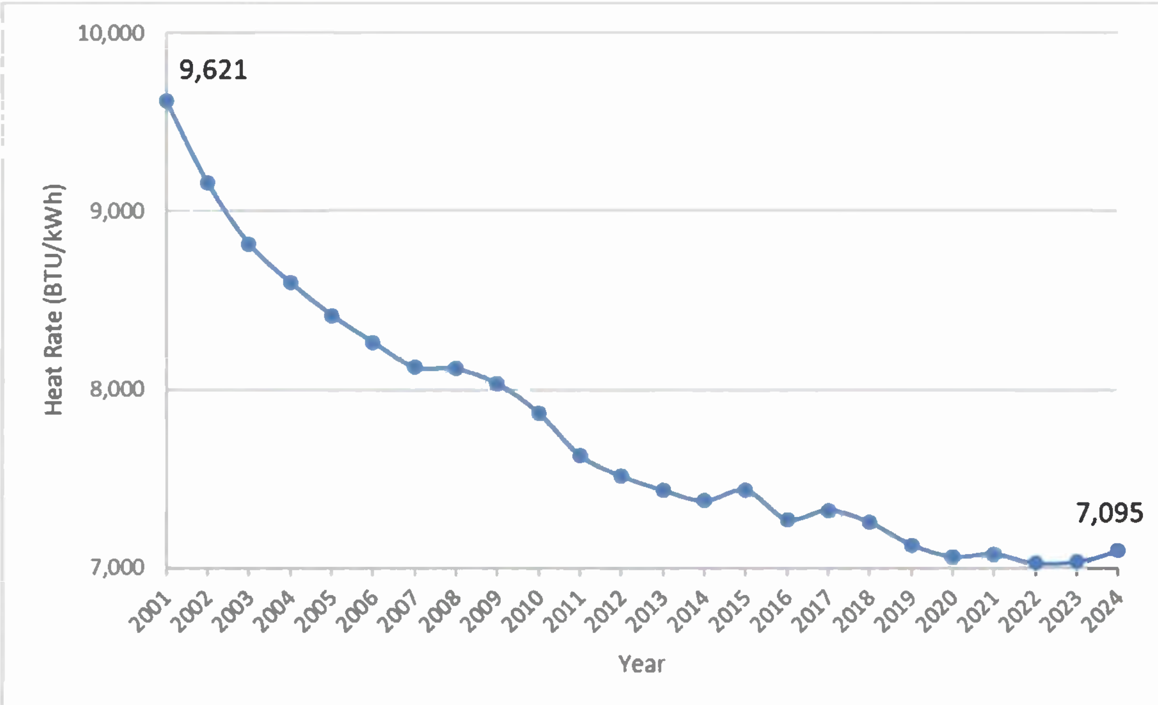
Factor # 6: The fuel cost and efficiency of FPL's fossil-fueled generation fleet and the avoidance of fuel costs through increased solar generation. There are two main factors that drive utility system costs for FPL's fossil-fueled generation fleet: (i) forecasted natural gas costs, and (ii) the efficiency with which generating units convert fuel into electricity. Forecasted natural gas costs have recently been one of the lowest cost options for fuel, leading to low overall system fuel costs for FPL's customers when compared with fuels such as oil and coal. In addition to these low natural gas costs, FPL customers also experience lower rates resulting from two other characteristics of FPL's system: 1) the amount of solar generation on FPL's system and 2) the efficiency of FPL's fossil-fueled generating units.

In 2024, FPL projects that its customers saved approximately $218 million in system fuel costs from having solar generation on its system. Since 2017 (when FPL began scaling investment in cost-effective large scale universal solar facilities), FPL has avoided approximately $1.1 billion of fuel costs because of its solar generation.

FPL has built a generating fleet that is increasingly fuel efficient. The amount of natural gas (measured in British Thermal Units, or BTU) needed to produce a kilowatt-hour (kWh) of electricity has declined from approximately 9,621 in 2001 to approximately 7,095 in 2024 as shown in Figure ES-2 below. This improvement of approximately 27% in fuel efficiency is truly significant, especially when considering the 20,000 MW-plus magnitude of gas-fueled generation on FPL's system. This trend of increasing system efficiency is very beneficial to a utility's customers as it helps to lower customers' electric rates.[5]

[5] However, because the potential benefits of utility DSM programs are based on DSM's ability to avoid utility system costs, such as fuel costs, the trend of steadily decreasing system fuel $/MWh costs automatically results in a significant lowering of the cost-effectiveness of utility DSM programs that focus on reducing annual energy use.

Figure ES-2: FPL System Heat Rate (2001-2024)



This significant improvement in FPL's fuel efficiency has resulted in FPL customers saving $650 million in fuel costs in 2024, and an estimated cumulative savings for FPL customers of approximately $15.3 billion from 2001 through 2024.

Factor # 7: Projected changes in CO_2 regulation and associated compliance costs. Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has utilized projected compliance costs for CO_2 emissions prepared by an independent consultant, ICF, in its resource planning work. FPL continues to utilize ICF's forecast of projected CO_2 compliance costs in its resource planning process. The projected compliance costs in the current plan are the same as those used in the 2024 Ten Year Site Plan.

Factor # 8: Projected increases in electric vehicle (EV) adoption. FPL's current load forecast continues to project increasing levels of EV adoption throughout the ten-year period. These projected impacts of EVs on annual energy usage and peak loads are discussed later in this document in Chapter II.

Factor # 9: Enhancing system reliability to prepare for extreme weather events. Over the past several years, extreme weather events have caused significant outages and disruptions to electric grids across the country. These events include widespread hot weather in California in the summer of 2020, historic cold weather in February 2021 in Texas, and extreme cold conditions throughout the Mid-Atlantic and Southeast around Christmas of 2022. FPL's Northwest FL area has continually set records in winter peak demand, including its latest record peak early in 2025 when widespread snowfall occurred throughout northern Florida. In addition to these events, FPL's service area regularly experiences periods of hotter than average weather throughout the year and hurricanes that can potentially affect the output of its generation fleet. While FPL does not plan its system around extreme events, it continues to believe it is prudent to consider and prepare for the possibility of extreme weather events and the ability to reliably serve customers under those circumstances. To that end, FPL has reviewed the lessons learned from the outages and service disruptions experienced in other jurisdictions and enhanced its own system so that it is adequately prepared. This includes winterizing FPL's nuclear and fossil-fueled generation units, enhancing cooperation and preparation between FPL and suppliers of natural gas and fuel oil, and keeping generation units as "extreme winter only" units that will provide the lowest cost backup capacity in the event of extreme winter weather in FPL's service area. The battery storage units that FPL is adding throughout the ten-year period will also provide additional reliable capacity during extreme weather events.

FPL will continue to work with regulatory authorities, such as the Federal Energy Regulatory Commission (FERC), the FPSC, and the North American Electric Reliability Corporation (NERC), to follow their guidance regarding proper planning procedures for extreme weather events.

<u>Factor # 10: Enhancing the system for resource adequacy and system reliability throughout the entire year.</u>
FPL's planning processes center around maintaining the reliability of its bulk electric system. For over the past two decades, the metric that drove most of FPL's reliability needs was its minimum 20% standard reserve margin, calculated at the time of summer and winter peak load. However, FPL's evolving system requires more in-depth reliability metrics to fully analyze resource adequacy across every hour of the year and through various potential scenarios, including variations in load, generating outages, and solar performance. Therefore, FPL has expanded use of its LOLP metric to include stochastic modeling that fully encompasses all of these scenarios, leading to a more robust evaluation of the reliability and resource adequacy of FPL's system. FPL's planned resources in this Site Plan address resource adequacy concerns by adding a variety of resources throughout the ten-year period that results in a robust, reliable, and cost-effective system to serve FPL's customers. This expanded methodology is discussed more thoroughly in Chapter III.

Each of these factors described above will continue to be examined in FPL's ongoing resource planning work in 2025 and future years.

IV. FPL's Projected Resource Plan:

FPL's projected resource plan for the 2025 Site Plan is shown below. Regarding the resources projected in the Site Plan, no final decisions are needed at this time, nor have any decisions been made regarding many of the resource additions shown in the resource plan presented in this 2025 Site Plan. This is particularly relevant to resource additions shown for the years 2030 through 2034. Consequently, resource additions shown for these later years are more prone to change in the future.

Table ES-1: Resource Additions/Subtractions in FPL's Resource Plan

Year	Changes to Existing Generation	Subtractions	New Generation Additions	Summer RM%
2025	+18 MW CC Upgrades	Pea Ridge (12 MW)	894 MW SoBRA*	22.4
2026			521.5 MW Battery NWFL** 894 MW Solar 1,419.5 MW Battery	24.1
2027	+48 MW CC Upgrades	Broward South (4 MW)	1,192 MW Solar 819.5 MW Battery	27.2
2028	+14 MW CC Upgrades	Lansing Smith 3A (32 MW)	1,490 MW Solar 596 MW Battery	26.6
2029		GCEC 4 (75 MW), GCEC 5 (75 MW)	1,788 MW Solar 596 MW Battery	26.3
2030		Perdido 1&2 (3 MW)	2,235 MW Solar 596 MW Battery	25.8
2031			2,235 MW Solar 596 MW Battery	25.7
2032		Palm Beach SWA 1 (40 MW)	2,235 MW Solar 2x0 Manatee CT (475 MW)	25.4
2033			2,235 MW Solar 1,192 MW Battery	25.5
2034			2,235 MW Solar 1,267 MW Battery	25.1
		Nameplate Solar Additions (2025-2034):	17,433	
		Nameplate Storage Additions (2025-2034):	7,603	

All solar and battery storage additions are in nameplate MW.
* These solar facilities were approved in FPL's 2021 Rate Case Settlement. All other solar additions will be presented to the FPSC for approval of cost recovery at a later date once the specific sites and costs for these additions are finalized.
** These battery storage units are projected to have an in-service date of October 01, 2025.

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CHAPTER I

Description of Existing Resources

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I.A FPL System:

I.A.1 Description of Existing Resources

FPL's service area (including the former Gulf Power area now referred to as FPL NWFL) contains approximately 35,000 square miles. Currently, FPL serves more than 6 million customer accounts representing approximately 12 million people in 43 counties in peninsular and Northwest Florida. These customers are served by a variety of resources including FPL-owned fossil-fuel, renewable (solar), and nuclear generating units; non-utility owned generation; DSM; and purchased power.

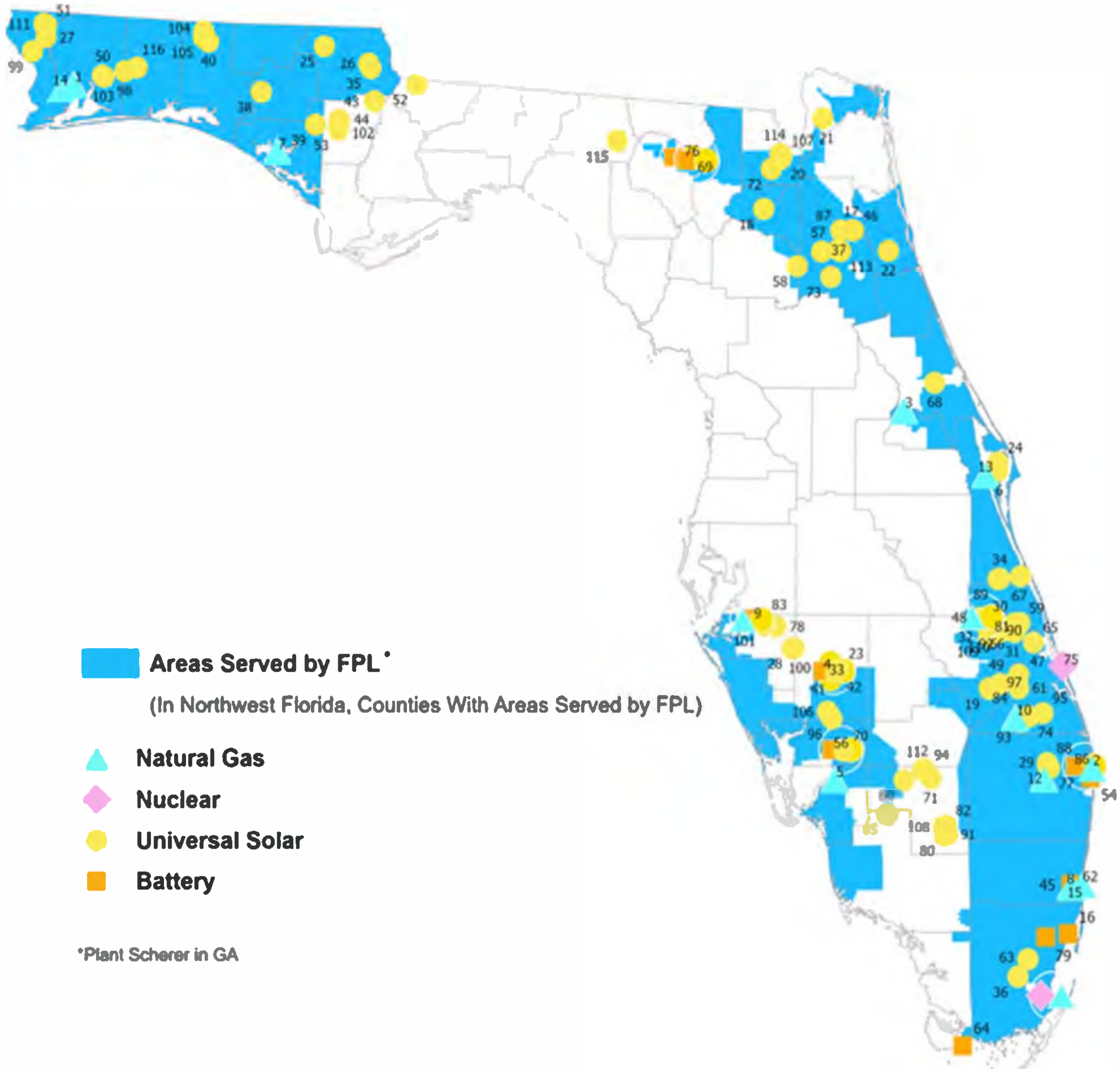
I.A.2 FPL - Owned Resources

As of December 31, 2024, FPL owned electric generating resources located at 116 sites distributed geographically throughout its service area and one site in Georgia (partial FPL ownership of one unit). These generating facilities consist of: four nuclear units, one coal steam-unit (the aforementioned partially owned unit in Georgia), 17 combined-cycle (CC) units, six fossil steam units, four gas turbines (GTs), 17 simple-cycle combustion turbines (CTs), two landfill gas units, three battery storage units, and 96 solar PV facilities. The locations of the 150 generating units that were in commercial operation on December 31, 2024, are shown on Figure I.A.2.1 and in Table I.A.2.1.

FPL's bulk transmission system, including both overhead and underground lines, is comprised of approximately 9,500 circuit miles of transmission lines. Integration of the generation, transmission, and distribution systems is achieved through FPL's 921 substations in Florida.

The existing FPL system, including generating plants, major transmission stations, and transmission lines, is shown on Figure I.A.2.2.

FPL Generating Resources by Location



There are four small battery pilot projects shown on the map that are not listed in Table I.A.2: #26 – Florida Bay, #32 – Southwest, #36 – Wynwood, and #57 – FIU Microgrid. These sites are discussed in Chapter III.

Figure I.A.2.1: FPL's Generating Resources by Location (as of December 31, 2024)

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 1 of 4

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	Nuclear				
75	St. Lucie [2/]	St. Lucie County, FL	2	Nuclear	1,821
11	Turkey Point	Miami-Dade County, FL	2	Nuclear	1,681
	Total Nuclear:		**4**		**3,502**
	Coal Steam				
-	Scherer*	Monroe County, Ga	1	Coal	215
	Total Coal Steam:		**1**		**215**
	Combined-Cycle				
5	Fort Myers	Lee County, FL	1	Gas	1,822
9	Manatee	Manatee County, FL	1	Gas	1,246
3	Sanford	Volusia County, FL	2	Gas	2,418
7	Lansing Smith*	Bay County, FL	1	Gas	641
13	Cape Canaveral	Brevard County, FL	1	Gas/Oil	1,290
10	Martin	Martin County, FL	3	Gas/Oil	2,223
55	Okeechobee [3/]	Okeechobee County, FL	1	Gas/Oil	1,720
62	Port Everglades	City of Hollywood, FL	1	Gas/Oil	1,237
2	Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,290
11	Turkey Point	Miami-Dade County, FL	1	Gas/Oil	1,292
12	West County	Palm Beach County, FL	3	Gas/Oil	3,771
45	Dania Beach Clean Energy Center	Broward County, FL	1	Gas/Oil	1,246
	Total Combined Cycle:		**17**		**20,196**
	Gas/Oil Steam				
9	Manatee [4/]	Manatee County, FL	2	Gas/Oil	0
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas Steam	961
	Total Oil/Gas Steam:		**6**		**961**
	Gas Turbines(GT)				
5	Fort Myers (GT)	Lee County, FL	2	Oil	102
8	Lauderdale (GT)	Broward County, FL	2	Gas/Oil	69
	Total Gas Turbines/Diesels:		**4**		**171**
	Combustion Turbines				
8	Lauderdale	Broward County, FL	5	Gas/Oil	1,155
5	Fort Myers	Lee County, FL	4	Gas/Oil	852
1	Pea Ridge*	Santa Rosa County, FL	3	Gas	12
7	Lansing Smith*	Bay County, FL	1	Oil	32
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas	926
	Total Combustion Turbines:		**17**		**2,977**
	Land Fill Gas				
69	Perdido LFG*	Escambia County, FL	2	LFG	3
	Total LFG:		**2**		**3**

1/ The solar capacity values shown are nameplate capacity only, not firm capacity. Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.
2/ Total capability of St. Lucie 1 is 981 Summer /1,003 Winter MW. FPL's share of St. Lucie 2 is 840 Summer /860 Winter MW. FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively.
3/ As part of the Okeechobee Hydrogen Gas Pilot Program, a portion of the CO_2 generated from the unit is transferred to an electrolyzer where it is then converted into Hydrogen Gas.
4/ Manatee Units 1 & 2 are Winter Peaking ONLY units. They will only be manned and operated during an Extreme Winter event in which additional capacity is needed to meet load.
* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Map Key "-" is shown for units that are located outside the State of Florida and therefore do not appear on the Map in Figure I.A.2.1.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 2 of 4

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1/]
	Battery Storage				
9	Manatee Battery Storage	Manatee County, FL	1	Storage	409
69	Sunshine Gateway Battery Storage	Columbia County, FL	1	Storage	30
76	Echo River Battery Storage	Suwannee County, FL	1	Storage	30
	Total Battery Storage:		**3**		**469**
	PV				
4	DeSoto Solar	DeSoto County, FL	1	Solar Energy	25
56	Babcock Ranch Solar	Charlotte County, FL	1	Solar Energy	74.5
41	Citrus Solar	DeSoto County, FL	1	Solar Energy	74.5
9	Manatee Solar	Manatee County, FL	1	Solar Energy	74.5
6	Space Coast Solar	Brevard County, FL	1	Solar Energy	10
65	Interstate Solar	St. Lucie County, FL	1	Solar Energy	74.5
63	Miami Dade Solar	Miami-Dade County, FL	1	Solar Energy	74.5
68	Pioneer Trail Solar	Volusia County, FL	1	Solar Energy	74.5
69	Sunshine Gateway Solar	Columbia County, FL	1	Solar Energy	74.5
58	Horizon Solar	Alachua County, FL	1	Solar Energy	74.5
42	Wildflower Solar	DeSoto County, FL	1	Solar Energy	74.5
66	Indian River Solar	Indian River County, FL	1	Solar Energy	74.5
57	Coral Farms Solar	Putnam County, FL	1	Solar Energy	74.5
60	Hammock Solar	Hendry County, FL	1	Solar Energy	74.5
67	Barefoot Bay Solar	Brevard County, FL	1	Solar Energy	74.5
59	Blue Cypress Solar	Indian River County, FL	1	Solar Energy	74.5
61	Loggerhead Solar	St. Lucie County, FL	1	Solar Energy	74.5
70	Babcock Preserve Solar	Charlotte County, FL	1	Solar Energy	74.5
71	Blue Heron Solar	Hendry County, FL	1	Solar Energy	74.5
23	Cattle Ranch Solar	DeSoto County, FL	1	Solar Energy	74.5
76	Echo River Solar	Suwannee County, FL	1	Solar Energy	74.5
20	Egret Solar	Baker County, FL	1	Solar Energy	74.5
77	Hibiscus Solar	Palm Beach County, FL	1	Solar Energy	74.5
19	Lakeside Solar	Okeechobee County, FL	1	Solar Energy	74.5
21	Nassau Solar	Nassau County, FL	1	Solar Energy	74.5
72	Northern Preserve Solar	Baker County, FL	1	Solar Energy	74.5
55	Okeechobee Solar	Okeechobee County, FL	1	Solar Energy	74.5
78	Southfork Solar	Manatee County, FL	1	Solar Energy	74.5
74	Sweetbay Solar	Martin County, FL	1	Solar Energy	74.5
22	Trailside Solar	St. Johns County, FL	1	Solar Energy	74.5
73	Twin Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
18	Union Springs Solar	Union County, FL	1	Solar Energy	74.5
17	Magnolia Springs Solar	Clay County, FL	1	Solar Energy	74.5
31	Pelican Solar	St. Lucie County, FL	1	Solar Energy	74.5
34	Palm Bay Solar	Brevard County, FL	1	Solar Energy	74.5
33	Rodeo Solar	DeSoto County, FL	1	Solar Energy	74.5
24	Discovery Solar	Brevard County, FL	1	Solar Energy	74.5
30	Orange Blossom Solar	Indian River County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.
* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW 1/
	PV Continued				
29	Sabal Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
32	Fort Drum Solar	Okeechobee County, FL	1	Solar Energy	74.5
28	Willow Solar	Manatee County, FL	1	Solar Energy	74.5
82	Ghost Orchid Solar	Hendry County, FL	1	Solar Energy	74.5
80	Sawgrass Solar	Hendry County, FL	1	Solar Energy	74.5
84	Sundew Solar	St. Lucie County, FL	1	Solar Energy	74.5
85	Immokalee Solar	Collier County, FL	1	Solar Energy	74.5
81	Grove Solar	Indian River County, FL	1	Solar Energy	74.5
83	Elder Branch Solar	Manatee County, FL	1	Solar Energy	74.5
25	Blue Indigo Solar*	Jackson County, FL	1	Solar Energy	74.5
26	Blue Springs Solar*	Jackson County, FL	1	Solar Energy	74.5
27	Cotton Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
46	Anhinga Solar	Clay County, FL	1	Solar Energy	74.5
35	Apalachee Solar*	Jackson County, FL	1	Solar Energy	74.5
50	Blackwater Solar*	Santa Rosa County, FL	1	Solar Energy	74.5
49	Bluefield Preserve Solar	St. Lucie County, FL	1	Solar Energy	74.5
48	Cavendish Solar	Okeechobee County, FL	1	Solar Energy	74.5
40	Chautauqua Solar*	Walton County, FL	1	Solar Energy	74.5
43	Chipola Solar*	Calhoun County, FL	1	Solar Energy	74.5
38	Cypress Pond Solar*	Washington County, FL	1	Solar Energy	74.5
37	Etonia Creek Solar	Putnam County, FL	1	Solar Energy	74.5
36	Everglades Solar	Miami-Dade County, FL	1	Solar Energy	74.5
51	First City Solar*	Escambia County, FL	1	Solar Energy	74.5
44	Flowers Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
47	Pink Trail Solar	St. Lucie County, FL	1	Solar Energy	74.5
39	Saw Palmetto Solar*	Bay County, FL	1	Solar Energy	74.5
53	Shirer Branch Solar*	Calhoun County, FL	1	Solar Energy	74.5
52	Wild Azalea Solar*	Gadsden County, FL	1	Solar Energy	74.5
91	Beautyberry Solar	Hendry County, FL	1	Solar Energy	74.5
94	Caloosahatchee Solar	Hendry County, FL	1	Solar Energy	74.5
98	Canoe Solar*	Okaloosa County, FL	1	Solar Energy	74.5
89	Ibis Solar	Brevard County, FL	1	Solar Energy	74.5
93	Monarch Solar	Martin County, FL	1	Solar Energy	74.5
90	Orchard Solar	Indian River/St. Lucie County, FL	1	Solar Energy	74.5
97	Pineapple Solar	St. Lucie County, FL	1	Solar Energy	74.5
96	Prairie Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
88	Silver Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
87	Terrill Creek Solar	Clay County, FL	1	Solar Energy	74.5
92	Turnpike Solar	Indian River County, FL	1	Solar Energy	74.5
95	White Tail Solar	Martin County, FL	1	Solar Energy	74.5
103	Big Juniper Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
102	Fourmile Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
106	Hawthorne Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
107	Nature Trail Solar	Baker County, FL	1	Solar Energy	74.5

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.
* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

Table I.A.2.1: FPL's Capacity Resources by Unit Type (as of December 31, 2024)

Page 4 of 4

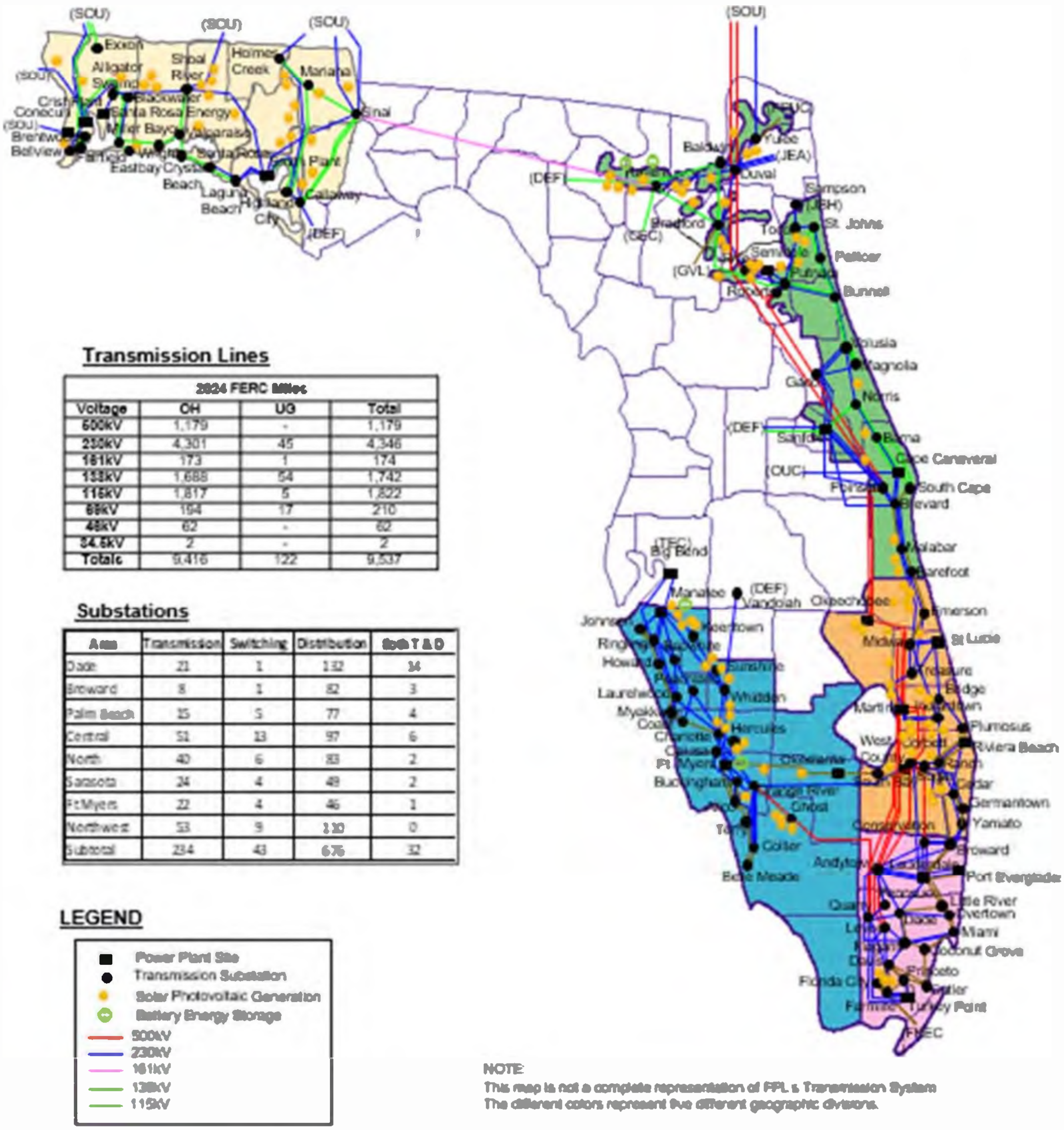
Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW 1/
	PV 5/ Continued				
104	Pecan Tree Solar*	Walton County, FL	1	Solar Energy	74.5
100	Sambucus Solar	Manatee County, FL	1	Solar Energy	74.5
99	Sparkleberry Solar*	Escambia County, FL	1	Solar Energy	74.5
101	Three Creeks Solar	Manatee County, FL	1	Solar Energy	74.5
105	Wild Quail Solar*	Walton County, FL	1	Solar Energy	74.5
108	Woodyard Solar	Hendry County, FL	1	Solar Energy	74.5
110	Buttonwood Solar	St. Lucie County, FL	1	Solar Energy	74.5
114	Cedar Trail Solar	Baker County, FL	1	Solar Energy	74.5
113	Georges Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
112	Hendry Isles Solar	Hendry County, FL	1	Solar Energy	74.5
109	Honeybell Solar	Okeechobee County, FL	1	Solar Energy	74.5
111	Mitchell Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
116	Kayak Solar*	Okaloosa County, FL	1	Solar Energy	74.5
115	Norton Creek Solar	Madison County, FL	1	Solar Energy	74.5
	Total Nameplate PV:		**96**		**7,038**
		Total Units:	**150**		**35,531**
		Nameplate System Generation as of December 31, 2024 =			**35,531**
		Firm System Generation as of December 31, 2024 =			**31,691**

1/ The solar capacity values shown are nameplate capacity only, not firm capacity.
Information on Summer and Winter Firm capacity for solar units is provided in Schedule 1.

* Represents units located in the former Gulf Service Area but are now part of FPL's system and fall under the FPL NW region.

FPL Bulk Transmission System

FPL Substation and Transmission System Configuration



Transmission Lines

2024 FERC Miles			
Voltage	OH	UG	Total
500kV	1,179	-	1,179
230kV	4,301	45	4,346
161kV	173	1	174
138kV	1,688	54	1,742
115kV	1,817	5	1,822
69kV	194	17	210
46kV	62	-	62
34.5kV	2	-	2
Totals	9,416	122	9,537

Substations

Area	Transmission	Switching	Distribution	Both T & D
Dade	21	1	132	14
Broward	8	1	82	3
Palm Beach	15	5	77	4
Central	51	13	97	6
North	40	6	83	2
Sarasota	24	4	49	2
Ft Myers	22	4	46	1
Northwest	53	9	110	0
Subtotal	234	43	676	32

LEGEND

NOTE:
This map is not a complete representation of FPL's Transmission System
The different colors represent five different geographic divisions.

Figure I.A.2.2: FPL Bulk Transmission System

I.A.3 FPL - Capacity and Energy Power Purchases

Firm Capacity: Purchases from Qualifying Facilities (QF)

Firm capacity power purchases remain part of FPL's resource mix. A cogeneration facility is one that simultaneously produces electrical and thermal energy, with the thermal energy (*e.g.*, steam) used for industrial, commercial, or cooling and heating purposes. A small power production facility is one that does not exceed 80 MW (unless it is exempted from this size limitation by the Solar, Wind, Waste, and Geothermal Power Production Incentives Act of 1990) and uses solar, wind, waste, geothermal, or other renewable resources as its primary energy source.

FPL currently has a contract to purchase firm capacity and energy from the Broward South qualifying facility during the ten-year reporting period of this Site Plan. The 2024 actual and 2025-2034 projected contributions from these facilities are shown in Table I.A.3.1, Table I.A.3.2, and Table I.A.3.3.

Firm Capacity: Purchases from Utilities

FPL currently does not have any firm purchases from other utilities planned.

Firm Capacity: Other Purchases

FPL has four other firm capacity purchase contracts. Two of these contracts are with the Palm Beach Solid Waste Authority, and two are with Morgan Stanley Capital Group's Kingfisher I and Kingfisher II wind projects. Table I.A.3.2 and I.A.3.3 present the Summer and Winter MW, respectively, resulting from these contracts under the category heading of Other Purchases.

Non-Firm (As Available) Energy Purchases

FPL purchases non-firm (as-available) energy from cogeneration and small power production facilities including energy from three solar PV facilities. The lower half of Table I.A.3.1 shows the amount of energy purchased in 2024 from these facilities along with the amount of energy purchased from customer-sited generation.

Table I.A.3.1: FPL's Purchased Power Resources by Contract (as of December 31, 2024)

Firm Capacity Purchases (MW)	Location (City or County)	Fuel	Summer MW
I. Purchase from QF's: Cogeneration/Small Power Production Facilities			
Broward South Landfill (firm)	Broward	Solid Waste	3.5
		Total:	3.5
II. Purchases from Utilities & IPP			
Santa Rosa, Southern Company Services		Natural Gas	230
Palm Beach SWA - REF 1	Palm Beach	Solid Waste	40
Palm Beach SWA - REF 2	Palm Beach	Solid Waste	70
MSCG - Kingfisher I	Oklahoma	Wind	53
MSCG - Kingfisher II	Oklahoma	Wind	28
		Total:	421
		Total Net Firm Generating Capability:	**425**

Non-Firm Energy Purchases (MWH)

Project	County	Fuel	Energy (MWH) Delivered to FPL in 2024
Miami Dade Resource Recovery [1/]	Dade	Solid Waste	-
Broward South Landfill (as-available) [1/]	Broward	Solid Waste	45,118
Lee County Solid Waste[1/]	Lee	Solid Waste	19,532
Next Era energy Resources - Brevard Landfill [1/]	Brevard	Landfill Gas	36,260
Florida Crystals - Okeelanta [1/]	Palm Beach	Bagasse/Wood	38,508
Waste Management Renewable Energy - Collier Landfill [1/]	Collier	Landfill Gas	345
Next Era Energy Resources - Seminole Landfill [1/]	Seminole	Landfill Gas	12,602
Tropicana - Bradenton	Manatee	Natural Gas	10,899
Georgia Pacific Palatka Mill	Putnam	Paper by-product	7,376
Aria Energy - Sarasota Landfill [1/]	Sarasota	Landfill Gas	1,788
Waste Management Renewable Energy - Broward Landfill [1/]	Broward	Landfill Gas	2,186
Fortistar - Charlotte Landfill [1/]	Charlotte	Landfill Gas	102
Customer Owned PV & Wind [1/]	Various	PV/Wind	770,381
International Paper Company [1/]	Escambia	Biomass	968
Ascend Performance Materials	Escambia	Gas	31,356
Gulf Coast Solar Center I , II, III[1/]	Various	Sun	226,722
Total Energy from Renewable Non-Firm Purchases Delivered to FPL in 2024 [1/]:			**1,161,888**
Total Energy from All Non-Firm Purchases Delivered to FPL in 2024:			**1,204,143**

1/ These Non-Firm Energy Purchases are renewable and are reflected on Schedule 11.1, row 9, column 6.

Table I.A.3.2: FPL's Firm Purchased Power Summer MW

Summary of FPL's Firm Capacity Purchases: Summer MW (for August of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Broward South Landfill	01/01/93	12/31/26	1.4	1.4	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	1.5	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0.6	0	0	0	0	0	0	0	0
		QF Purchases Subtotal:	**3.5**	**3.5**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
None	-	-	-	-	-	-	-	-	-	-	-	-
		Utility Purchases Subtotal:	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total of QF and Utility Purchases =	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Palm Beach SWA - REF1 [1/]	01/01/12	04/01/32	40	40	40	40	40	40	40	0	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	70	0
MSCG - Kingfisher I [2/]	01/01/17	12/31/35	53	53	53	53	53	53	53	53	53	53
MSCG - Kingfisher II [2/]	01/01/17	12/31/35	28	28	28	28	28	28	28	28	28	28
Gulf Solar PPAs [3/]	11/17/14	12/31/42	41	40	40	40	40	40	40	40	40	40
		Other Purchases Subtotal:	**232**	**231**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Total "Non-QF" Purchases =	**232**	**231**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Summer Firm Capacity Purchases Total MW:	**235**	**235**	**231**	**231**	**231**	**231**	**231**	**191**	**191**	**121**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".
2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.
3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermittent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

Table I.A.3.3: FPL's Firm Purchased Power Winter MW

Summary of FPL's Firm Capacity Purchases: Winter MW (for January of Year Shown)

I. Purchases from QF's

Cogeneration Small Power Production Facilities	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Broward South Landfill	01/01/93	12/31/26	1.4	1.4	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/95	12/31/26	1.5	1.5	0	0	0	0	0	0	0	0
Broward South Landfill	01/01/97	12/31/26	0.6	0.6	0	0	0	0	0	0	0	0
		QF Purchases Subtotal:	**3.5**	**3.5**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**	**0**

II. Purchases from Utilities

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
None	-	-	-	-	-	-	-	-	-	-	-	-
		Utility Purchases Subtotal:	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Total of QF and Utility Purchases =	**3.5**	**3.5**	**0.0**	**0.0**	**0.0**	**0**	**0**	**0**	**0**	**0**

III. Other Purchases

	Contract Start Date	Contract End Date	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Santa Rosa, SCS	06/01/24	04/30/25	230	0	0	0	0	0	0	0	0	0
Palm Beach SWA - REF1 1/	01/01/12	04/01/32	40	40	40	40	40	40	40	40	0	0
Palm Beach SWA - REF2	01/01/15	06/01/34	70	70	70	70	70	70	70	70	70	70
MSCG - Kingfisher I 2/	01/01/17	12/31/35	71	71	71	71	71	71	71	71	71	71
MSCG - Kingfisher II 2/	01/01/17	12/31/35	38	38	38	38	38	38	38	38	38	38
Gulf Solar PPAs 3/	11/17/14	12/31/42	0	0	0	0	0	0	0	0	0	0
		Other Purchases Subtotal:	**449**	**219**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

Total "Non-QF" Purchases =	**449**	**219**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Winter Firm Capacity Purchases Total MW:	**453**	**223**	**219**	**219**	**219**	**219**	**219**	**219**	**179**	**179**

1/ When the second unit came into commercial service at the Palm Beach SWA, neither unit met the standards to be a small power producer, and these became accounted for under "Other Purchases".
2/ These PPAs are from a variable wind source; however, the PPA supplier has committed to a certain amount of minimum MW per hour which FPL and Gulf treat as firm capacity for resource planning purposes.
3/ These PPAs are non-firm, energy-only contracts due to the unscheduled, intermittent nature of solar resources. For resource planning purposes, a portion of the nameplate rating of the solar facilities has been, and continues to, provide, on average, a non-zero value at the system Summer peak hour.

I.A.4 Demand-Side Management (DSM)

FPL has continually explored and implemented cost-effective DSM programs since 1978, and it has consistently been among the leading utilities nationally in achieving substantial DSM efficiencies. These programs include innovative conservation/energy efficiency and load management initiatives. In the FPL service area the company's DSM efforts through the end of 2024 have resulted in a cumulative Summer peak reduction of 5,695 MW at the generator and an estimated cumulative energy savings of 102,684 Gigawatt-Hours (GWh) at the generator. After accounting for the 20% total reserve margin requirement, FPL's DSM efforts through 2024 have eliminated the need to construct the equivalent of approximately sixty-eight (68) new 100 MW generating units. Also, it is important to note that FPL has achieved these significant DSM accomplishments while minimizing the DSM-based impact on electric rates for all of its customers by using the Rate Impact Measure (RIM) cost-effectiveness screening calculation approach.

In 2024, the Florida Public Service Commission (FPSC) set DSM Goals for the years 2025 through 2034 for FPL and the other Florida utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). In March 2025, FPL filed for FPSC approval its DSM Plan with which it intends to meet the DSM Goals. In this Site Plan, FPL assumes that the annual reduction values for Summer MW, Winter MW, and energy (MWh) set forth in the DSM Goals order (Order No. PSC-2024-0505-FOF-EG) will be met as shown in various schedules presented in this Site Plan.

I.A.5 Existing Generating Units in FPL's Service Area

Schedule 1 presents the generating capacity in FPL's service area as of December 31, 2024.

Schedule 1: FPL Existing Generating Facilities as of December 31, 2024

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
									Alt.		Actual/					
							Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability 1/		Firm Capability 2/	
	Unit			Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Anhinga Solar 2/		FPL	Clay County													
			29.88213,-81.67618									74,500	74.5	74.5	1.86	28.46
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.86	28.46
Apalachee Solar 2/		FPL NWFL	Jackson County													
			30.76055,-85.06952									74,500	74.5	74.5	0.00	36.04
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	36.04
Babcock Preserve Solar 2/		FPL	Charlotte County													
			32,33/41S/26E : 4/42S/26E									74,500	74.5	74.5	0.00	37.24
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	37.24
Babcock Ranch Solar 2/		FPL	Charlotte County													
			29,31,32/41S/26E									74,500	74.5	74.5	0.00	37.38
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	37.38
Barefoot Bay Solar 2/		FPL	Brevard County													
			1, 10, 15,16/30S/38E									74,500	74.5	74.5	0.00	41.42
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	41.42
Beautyberry Solar 2/		FPL	Hendry County													
			26.373000, -81.026000									74,500	74.5	74.5	2.55	30.08
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.55	30.08
Big Juniper Solar 2/		FPL NWFL	Santa Rosa County													
			30.639000, -86.925000									74,500	74.5	74.5	0.00	36.76
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	36.76
Blackwater Solar 2/		FPL NWFL	Santa Rosa County													
			30.64691,-86.93821									74,500	74.5	74.5	0.00	27.88
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	27.88
Blue Cypress Solar 2/		FPL	Indian River County													
			16/33S/38E									74,500	74.5	74.5	0.00	39.77
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	39.77
Blue Heron Solar 2/		FPL	Hendry County													
			28,33/43S/32E									74,500	74.5	74.5	0.00	37.55
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	37.55
Blue Indigo Solar 2/		FPL NWFL	Jackson County													
			2/5N/12W : 35,36/6N/12W									74,500	74.5	74.5	0.00	49.96
	1			PV	Solar	Solar	N/A	N/A	--	Mar-20	Unknown	74,500	74.5	74.5	0.00	49.96
Blue Springs Solar 2/		FPL NWFL	Jackson County													
			36/5N/9W									74,500	74.5	74.5	0.02	41.01
	1			PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.02	41.01
Bluefield Preserve Solar 2/		FPL	St. Lucie County													
			27.24354,-80.67097									74,500	74.5	74.5	1.94	21.96
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.94	21.96
Buttonwood Solar 2/		FPL	St. Lucie County													
			27.548000, -80.672000									74,500	74.5	74.5	2.21	33.66
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.21	33.66
Caloosahatchee Solar 2/		FPL	Hendry County													
			26.752000, -81.180000									74,500	74.5	74.5	1.93	29.66
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.93	29.66

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel		Alt.		Actual/		Net Capability 1/		Firm Capability 2/	
	Unit			Unit	Fuel		Transport.		Fuel Days	Commercial In-Service	Expected Retirement	Gen.Max. Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Canoe Solar 2/		FPL NWFL	Okaloosa County													
			30.680000, -86.782000									74,500	74.5	74.5	0.00	37.13
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.00	37.13
Cape Canaveral		FPL	Brevard County													
			19/23S/36E									1,418,000	1,418	1,290	1,418	1,290
	3			CC	NG	FO_2	PL	TK	Unknown	Apr-13	Unknown	1,418,000	1,418	1,290	1,418	1,290
Cattle Ranch Solar 2/		FPL	Desoto County													
			19,24,25/36S/26E									74,500	74.5	74.5	1.50	28.68
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	1.50	28.68
Cavendish Solar 2/		FPL	Okeechobee County													
			27.628,-80.80317									74,500	74.5	74.5	4.28	29.75
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	4.28	29.75
Cedar Trail Solar 2/		FPL NWFL	Baker County													
			30.322000, -82.192000									74,500	74.5	74.5	0.29	5.64
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.29	5.64
Chautauqua Solar 2/		FPL NWFL	Walton County													
			30.87576,-86.20813									74,500	74.5	74.5	0.00	40.13
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	40.13
Chipola Solar 2/		FPL NWFL	Calhoun County													
			30.45643,-85.27719									74,500	74.5	74.5	0.00	33.81
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	33.81
Citrus Solar 2/		FPL	DeSoto County													
			35/36S/25E : 2/37S/25E									74,500	74.5	74.5	0.00	38.80
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	38.80
Coral Farms Solar 2/		FPL	Putnam County													
			27,28,33,34/8S/24E									74,500	74.5	74.5	11.03	46.58
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	11.03	46.58
Cotton Creek Solar 2/		FPL NWFL	Jackson County													
			7/4N/8W									74,500	74.5	74.5	0.04	41.10
	1			PV	Solar	Solar	N/A	N/A	--	Dec-21	Unknown	74,500	74.5	74.5	0.04	41.10
Cypress Pond Solar 2/		FPL NWFL	Washington County													
			30.59444, -85.83008									74,500	74.5	74.5	0.00	37.17
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	37.17
Dania Beach Clean Energy Center		FPL	Broward County													
			30/50S/42E									1,252,000	1,252	1,246	1,252	1246
	7			CC	NG	FO_2	PL	TK	Unknown	Jan-22	Unknown	1,252,000	1,252	1,246	1,252	1,246
DeSoto Solar 2/		FPL	DeSoto County													
			27/36S/25E									22,950	25	25	0.71	10.27
	1			PV	Solar	Solar	N/A	N/A	Unknown	Oct-09	Unknown	22,950	25	25	0.71	10.27
Discovery Solar 2/		FPL	Brevard County													
			25,35,36/22S/36E									74,500	74.5	74.5	0.99	36.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	0.99	36.94
Echo River Battery Storage		FPL	Suwannee County													
			24,25,19/2S/14E : 30/2S/15E									30,000	30.0	30.0	30.0	30.0
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
							Fuel		Alt. Fuel	Commercial	Actual/ Expected	Gen.Max.	Net Capability [1/]		Firm Capability [2/]	
	Unit			Unit	Fuel		Transport.		Days	In-Service	Retirement	Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Echo River Solar [2/]		FPL	Suwannee County													
			24,25,19/2S/14E : 30/2S/15E									74,500	74.5	74.5	0.00	42.60
	1			FV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	42.60
Egret Solar [2/]		FPL	Baker County													
			26,27/2S/21E									74,500	74.5	74.5	0.28	38.16
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.28	38.16
Elder Branch Solar [2/]		FPL	Manatee County													
			18, 33S, 21E									74,500	74.5	74.5	0.51	32.19
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	0.51	32.19
Etonia Creek Solar [2/]		FPL	Putnam County													
			29.76723,-81.77749									74,500	74.5	74.5	1.39	34.34
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	1.39	34.34
Everglades Solar [2/]		FPL	Miami-Dade County													
			25.54255,-80.55434									74,500	74.5	74.5	3.14	23.94
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	3.14	23.94
First City Solar [2/]		FPL NWFL	Escambia County													
			30.91993,-87.34002									74,500	74.5	74.5	0.00	28.69
	1									Jan-23	Unknown	74,500	74.5	74.5	0.00	28.69
				FV	Solar	Solar	N/A	N/A	Unknown							
Flowers Creek Solar [2/]		FPL NWFL	Calhoun County													
			30.57013,-85.03932									74,500	74.5	74.5	0.00	34.22
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	34.22
Fort Drum Solar [2/]		FPL	Okeechobee County													
			2,11,13/33S/35E									74,500	74.5	74.5	0.99	34.80
	1			FV	Solar	Solar	N/A	N/A	Unknown	Aug-21	Unknown	74,500	74.5	74.5	0.99	34.80
Fort Myers		FPL	Lee County													
			35/43S/25E									2,911,000	2,911	2,776	2,911	2,776
	2			CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,920,000	1,920	1,822	1,920	1,822
	3			CT	NG	FO_2	TK	TK	Unknown	Jun-03	Unknown	868,000	868	852	868	852
	1, 9			GT	FO_2	No	WA	No	Unknown	May-74	Unknown	123,000	123	102	123	102
Fourmile Creek Solar [2/]		FPL NWFL	Calhoun County													
			30.441000, -85.276000									74,500	74.5	74.5	0.00	38.53
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	38.53
Georges Lake Solar [2/]		FPL	Putnam County													
			29.760000, -81.765000									74,500	74.5	74.5	0.63	5.00
	1			FV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.63	5.00
Ghost Orchid Solar [2/]		FPL	Hendry County													
			4,5 47S, 33E									74,500	74.5	74.5	1.95	22.08
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.95	22.08
Grove Solar [2/]		FPL	Indian River County													
			29, 33S, 37E									74,500	74.5	74.5	1.88	24.21
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.88	24.21
Gulf Clean Energy Center		FPL NWFL	Escambia County													
			25/1N/30W									1,901,000	1,901	1,887	1,901	1,887
	4			ST	NG	--	PL	--	--	Jul-59	4th Q 2029	75,000	75	75	75	75
	5			ST	NG	--	PL	--	--	Jun-61	4th Q 2029	75,000	75	75	75	75
	6			ST	NG	--	PL	--	--	May-70	Unknown	315,000	315	315	315	315
	7			ST	NG	--	PL	--	--	Aug-73	Unknown	496,000	496	496	496	496
	8			CT	NG	--	PL	--	--	Dec-21	Unknown	940,000	940	926	940	926

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport. Pri.	(8) Fuel Transport. Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability 1/ Winter MW	(14) Net Capability 1/ Summer MW	(15) Firm Capability 2/ Winter MW	(16) Firm Capability 2/ Summer MW
Hammock Solar 2/		FPL	Hendry County													
			34/43S/30E : 3,4,9,10/44S/30E									74,500	74.5	74.5	0.00	38.90
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.00	38.90
Hawthorne Creek Solar 2/		FPL	Desoto County													
			27.086000, -81.836000									74,500	74.5	74.5	1.18	31.49
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	1.18	31.49
Hendry Isles Solar 2/		FPL	Hendry County													
			26.749000, -81.192000									74,500	74.5	74.5	2.34	22.11
	1			FV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.34	22.11
Hibiscus Solar 2/		FPL	Palm Beach County													
			2/43S/40E									74,500	74.5	74.5	0.00	36.71
	1			FV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	36.71
Honeybell Solar 2/		FPL	Okeechobee County													
			27.522000, -80.744000									74,500	74.5	74.5	2.20	32.88
	1			FV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	2.20	32.88
Horizon Solar 2/		FPL	Alachua County													
			25,35,36/9S/22E : 30, 31/9S/23E									74,500	74.5	74.5	1.10	39.29
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	1.10	39.29
Ibis Solar 2/		FPL	Brevard County													
			27.853000, -80.682000									74,500	74.5	74.5	1.98	35.07
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.98	35.07
Immokalee Solar 2/		FPL	Collier County													
			4, 9, 16, 46S, 29E									74,500	74.5	74.5	2.47	20.70
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	2.47	20.70
Indian River Solar 2/		FPL	Indian River County													
			30/33S/38E									74,500	74.5	74.5	0.00	39.54
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	39.54
Interstate Solar 2/		FPL	St. Lucie County													
			28,33/34S/39E									74,500	74.5	74.5	0.00	37.94
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	37.94
Kayak Solar 2/		FPL NWFL	Okaloosa County													
			30.704000, -86.700000									74,500	74.5	74.5	0.00	10.97
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.00	10.97
Lakeside Solar 2/		FPL	Okeechobee County													
			28,29,32/37S/36E									74,500	74.5	74.5	1.18	36.08
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.18	36.08
Lansing Smith		FPL NWFL	Bay County													
			36/2S/15W									705,000	705	673	705	673
	3			CC	NG	--	PL	--	--	Apr-02	Unknown	665,000	665	641	665	641
	A			CT	LO	--	TK	--	--	May-71	4th Q 2027	40,000	40	32	40	32
Lauderdale		FPL	Broward County													
			30/50S/42E									1,228,400	1,218	1,224	1,218	1,224
	6			CT	NG	FO_2	PL	TK	Unknown	Dec-16	Unknown	1,155,000	1,145	1,155	1,145	1,155
	3, 5			GT	NG	FO_2	PL	TK	Unknown	Aug-70	Unknown	73,400	73	69	73	69
Loggerhead Solar 2/		FPL	St. Lucie County													
			21/37S/38E									74,500	74.5	74.5	0.58	26.38
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-18	Unknown	74,500	74.5	74.5	0.58	26.38

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.

2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

Schedule 1

FPL Existing Generating Facilities
As of December 31, 2024

(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
									Alt.		Actual/					
						Fuel			Fuel	Commercial	Expected	Gen.Max.	Net Capability [1/]		Firm Capability [2/]	
	Unit			Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Magnolia Springs Solar [2/]		FPL	Clay County													
			15,16,21,22/7S/26E									74,500	74.5	74.5	1.03	39.11
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.03	39.11
Manatee Battery Storage		FPL	Manatee County													
			1,12,13,24/33S/19E: 18,19/33S/20E									409,000	409	409	409	409
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	409,000	409	409	409	409
Manatee Solar [2/]		FPL	Manatee County													
			1,12,13,24/33S/19E: 18,19/33S/20E									74,500	74.5	74.5	0.00	38.70
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-16	Unknown	74,500	74.5	74.5	0.00	38.70
Manatee		FPL	Manatee County													
			18/33S/20E									2,986,000	1,348	1,246	1,348	1,246
	1 [3/]			ST	NG	FO_6	PL	WA	Unknown	Oct-76	4/	819,000	0	0	0	0
	2 [3/]			ST	NG	FO_6	PL	WA	Unknown	Dec-77	4/	819,000	0	0	0	0
	3			CC	NG	No	PL	No	Unknown	Jun-05	Unknown	1,348,000	1,348	1,246	1,348	1,246
Martin		FPL	Martin County													
			30/39S/38E									2,385,000	2,394	2,223	2,394	2,223
	3			CC	NG	No	PL	No	Unknown	Feb-94	Unknown	538,000	538	487	538	487
	4			CC	NG	No	PL	No	Unknown	Apr-94	Unknown	520,000	529	487	529	487
	8			CC	NG	FO_2	PL	TK	Unknown	Jun-05	Unknown	1,327,000	1,327	1,249	1,327	1,249
Miami Dade Solar [2/]		FPL	Miami-Dade County													
			13/55S/38E									74,500	74.5	74.5	0.00	36.14
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	36.14
Mitchell Creek Solar [2/]		FPL NWFL	Escambia County													
			30.928510, -87.364140									74,500	74.5	74.5	0.00	29.19
	1			PV	Solar	Solar	N/A	N/A	Unknown	Nov-24	Unknown	74,500	74.5	74.5	0.00	29.19
Monarch Solar [2/]		FPL	Martin County													
			27.030740, -80.524800									74,500	74.5	74.5	1.52	30.37
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.52	30.37
Nassau Solar [2/]		FPL	Nassau County													
			2/1N/24E									74,500	74.5	74.5	1.02	37.03
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.02	37.03
Nature Trail Solar [2/]		FPL	Baker County													
			30.313000, -82.177000									74,500	74.5	74.5	0.36	37.61
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.36	37.61
Northern Preserve Solar [2/]		FPL	Baker County													
			13,18/3S/20E: 24/3S/21E									74,500	74.5	74.5	0.00	33.61
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	33.61
Norton Creek Solar [2/]		FPL	Madison County													
			30.383000, -83.327000									74,500	74.5	74.5	0.03	24.27
	1			PV	Solar	Solar	N/A	N/A	Unknown	Dec-24	Unknown	74,500	74.5	74.5	0.03	24.27
Okeechobee [4/]		FPL	Okeechobee													
			2/33S/35E									1,720,000	1,672	1,720	1,672	1,720
	1			CC	NG	FO_2	PL	TK	Unknown	Mar-19	Unknown	1,720,000	1,672	1,720	1,672	1,720
Okeechobee Solar [2/]		FPL	Okeechobee County													
			1,12,13/33S/35E									74,500	74.5	74.5	0.00	36.21
	1			FV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	36.21

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
3/ Manatee Units 1 & 2 are Winter Peaking ONLY units. They will only be manned and operated during an Extreme Winter event in which additional capacity is needed to meet load.
4/ As part of the Okeechobee Hydrogen Gas Pilot Program, a portion of the CO_2 generated from the unit is transferred to an electrolyzer where it is then converted into Hydrogen Gas.

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FPL Existing Generating Facilities
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(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
									Alt.		Actual/					
							Fuel		Fuel	Commercial	Expected	Gen.Max.	Net Capability [1/]		Firm Capability [2/]	
	Unit			Unit	Fuel		Transport		Days	In-Service	Retirement	Nameplate	Winter	Summer	Winter	Summer
Plant Name	No.	Area	Location	Type	Pri.	Alt.	Pri.	Alt.	Use	Month/Year	Month/Year	KW	MW	MW	MW	MW
Orange Blossom Solar [2/]		FPL	Indian River County													
			19/33S/38E									74,500	74.5	74.5	1.21	37.83
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.21	37.83
Orchard Solar [2/]		FPL	Indian River/St. Lucie County													
			27.556000, -80.570000									74,500	74.5	74.5	2.92	35.99
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.92	35.99
Palm Bay Solar [2/]		FPL	Brevard County													
			19,30/30S/37E									74,500	74.5	74.5	0.83	39.78
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	0.83	39.78
Pea Ridge		FPL NWFL	Santa Rosa County													
			15/1N/29W									15,000	15	12	15	12
	1			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
	2			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
	3			CT	NG	--	PL	--	--	May-98	4th Q 2024	5,000	5	4	5	4
Pecan Tree Solar [2/]		FPL NWFL	Walton County													
			30.933000, -86.246000									74,500	74.5	74.5	0.00	40.07
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	40.07
Pelican Solar [2/]		FPL	St. Lucie County													
			6,7/34S/38E									74,500	74.5	74.5	1.85	37.61
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-21	Unknown	74,500	74.5	74.5	1.85	37.61
Perdido LFG		FPL NWFL	Escambia County													
												3,000	3	3	3	3
	1			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
	2			IC	LFG	--	PL	--	--	Oct-10	4th Q 2029	1,500	1.5	1.5	1.5	1.5
Pineapple Solar [2/]		FPL	St. Lucie County													
			27.255000, -80.571000									74,500	74.5	74.5	2.19	32.64
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.19	32.64
Pink Trail Solar [2/]		FPL	St. Lucie County													
			27.29783,-80.54214									74,500	74.5	74.5	2.58	21.84
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	2.58	21.84
Pioneer Trail Solar [2/]		FPL	Volusia County													
			21/17S/32E									74,500	74.5	74.5	0.00	35.63
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	35.63
Port Everglades		FPL	City of Hollywood													
			23/50S/42E									1,333,000	1,333	1,237	1,333	1,237
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-16	Unknown	1,333,000	1,333	1,237	1,333	1,237
Prairie Creek Solar [2/]		FPL	Desoto County													
			27.045000, -81.809000									74,500	74.5	74.5	1.37	32.07
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	1.37	32.07
Riviera Beach		FPL	City of Riviera Beach													
			33/42S/432E									1,406,000	1,406	1,290	1,406	1,290
	5			CC	NG	FO_2	PL	TK	Unknown	Apr-14	Unknown	1,406,000	1,406	1,290	1,406	1,290
Rodeo Solar [2/]		FPL	DeSoto County													
			23,24,25,26,27/36S/25E									74,500	74.5	74.5	1.50	36.68
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-21	Unknown	74,500	74.5	74.5	1.50	36.68
Sabal Palm Solar [2/]		FPL	Palm Beach County													
			33/42S/40E									74,500	74.5	74.5	1.53	38.21
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jun-21	Unknown	74,500	74.5	74.5	1.53	38.21

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

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(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW	(15) Firm Capability [2/] Winter MW	(16) Firm Capability [2/] Summer MW
Sambucus Solar [2/]		FPL	Manatee County													
			27.449000, -82.064000									74,500	74.5	74.5	0.93	30.74
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.93	30.74
Sanford		FPL	Volusia County													
			16/19S/30E									2,530,000	2,530	2,418	2,530	2,418
	4			CC	NG	No	PL	No	Unknown	Oct-03	Unknown	1,278,000	1,278	1,209	1,278	1,209
	5			CC	NG	No	PL	No	Unknown	Jun-02	Unknown	1,252,000	1,252	1,209	1,252	1,209
Saw Palmetto Solar [2/]		FPL NWFL	Bay County													
			30.4213,-85.44103									74,500	74.5	74.5	0.00	39.70
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-23	Unknown	74,500	74.5	74.5	0.00	39.70
Sawgrass Solar [2/]		FPL	Hendry County													
			20, 21, 28, 29, 47S, 33E									74,500	74.5	74.5	1.93	21.86
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.93	21.86
Scherer [5/]		FPL NWFL	Monroe, GA													
												215,000	215	215	215	215
	3			ST	C	--	RR	--	--	Jan-87	4th Q 2034	215,000	215	215	215	215
Shirer Branch Solar [2/]		FPL NWFL	Calhoun County													
			30.39891,-85.27975									74,500	74.5	74.5	0.00	39.47
	1			PV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	39.47
Silver Palm Solar [2/]		FPL	Palm Beach County													
			26.788000, -80.352000									74,500	74.5	74.5	2.64	30.94
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.64	30.94
Southfork Solar [2/]		FPL	Manatee County													
			26/33S/21E									74,500	74.5	74.5	0.00	43.15
	1			PV	Solar	Solar	N/A	N/A	Unknown	May-20	Unknown	74,500	74.5	74.5	0.00	43.15
Space Coast Solar [2/]		FPL	Brevard County													
			13/23S/36E									10,000	10	10	0.13	3.76
	1			PV	Solar	Solar	N/A	N/A	Unknown	Apr-10	Unknown	10,000	10	10	0.13	3.76
Sparkleberry Solar [2/]		FPL NWFL	Escambia County													
			30.763000, -87.433000									74,500	74.5	74.5	0.00	37.92
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	37.92
St. Lucie [6/]		FPL	St. Lucie County													
			16/36S/41E									1,863,000	1,863	1,821	1,863	1,821
	1			ST	Nuc	No	TK	No	Unknown	May-76	Unknown	1,003,000	1,003	981	1,003	981
	2			ST	Nuc	No	TK	No	Unknown	Jun-83	Unknown	860,000	860	840	860	840
Sundew Solar [2/]		FPL	St. Lucie County													
			17, 37S, 38E									74,500	74.5	74.5	1.91	26.32
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-22	Unknown	74,500	74.5	74.5	1.91	26.32
Sunshine Gateway Battery Storage		FPL	Columbia County													
			25,26,35,36/2S/15E : 31,32/5S/16E									30,000	30.0	30.0	30.0	30.0
	1			BS	N/A	N/A	N/A	N/A	Unknown	Dec-21	Unknown	30,000	30.0	30.0	30.0	30.0
Sunshine Gateway Solar [2/]		FPL	Columbia County													
			25,26,35,36/2S/15E : 31,32/5S/16E									74,500	74.5	74.5	0.00	40.31
	1			PV	Solar	Solar	N/A	N/A	Unknown	Jan-19	Unknown	74,500	74.5	74.5	0.00	40.31
Sweetbay Solar [2/]		FPL	Martin County													
			17,19/39S/39E									74,500	74.5	74.5	0.00	31.15
	1			PV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.00	31.15

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.
2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.
5/ Unit capabilities shown represent FPL NWFL's portion of Scherer Unit 3 (25%) located in Georgia.
6/ Total capability of St. Lucie 1 is 981 Summer/1,003 Winter MW. FPL's share of St. Lucie 2 is 840 Summer/860 Winter MW.
FPL's ownership share of St. Lucie Units 1 and 2 is 100% and 85%, respectively, as shown above. FPL's share of the deliverable capacity from each unit is approx. 92.5% and excludes the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 7.448% per unit.

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(1) Plant Name	(2) Unit No.	Area	(3) Location	(4) Unit Type	(5) Fuel Pri.	(6) Fuel Alt.	(7) Fuel Transport Pri.	(8) Fuel Transport Alt.	(9) Alt. Fuel Days Use	(10) Commercial In-Service Month/Year	(11) Actual/ Expected Retirement Month/Year	(12) Gen.Max. Nameplate KW	(13) Net Capability [1/] Winter MW	(14) Net Capability [1/] Summer MW	(15) Firm Capability [2/] Winter MW	(16) Firm Capability [2/] Summer MW
Terrill Creek Solar [2/]		FPL	Clay County													
			29.884000, -81.767000									74,500	74.5	74.5	0.66	34.21
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	0.66	34.21
Three Creeks Solar [2/]		FPL	Manatee County													
			27.581000, -82.260000									74,500	74.5	74.5	0.96	32.94
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.96	32.94
Trailside Solar [2/]		FPL	St. Johns County													
			25,36/8S/28E									74,500	74.5	74.5	1.02	39.55
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	1.02	39.55
Turkey Point		FPL	Miami Dade County													
			27/57S/40E									3,083,000	3,083	2,973	3,083	2,973
	3			ST	Nuc	No	TK	No	Unknown	Nov-72	Unknown	859,000	859	837	859	837
	4			ST	Nuc	No	TK	No	Unknown	Jun-73	Unknown	866,000	866	844	866	844
	5			CC	NG	FO2	PL	TK	Unknown	May-07	Unknown	1,358,000	1,358	1,292	1,358	1,292
Turnpike Solar [2/]		FPL	Indian River County													
			27.568000, -80.645000									74,500	74.5	74.5	2.84	34.60
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	2.84	34.60
Twin Lakes Solar [2/]		FPL	Putnam County													
			19,20,25/10S/24E : 30/10S/25E									74,500	74.5	74.5	0.96	38.32
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-20	Unknown	74,500	74.5	74.5	0.96	38.32
Union Springs Solar [2/]		FPL	Union County													
			3,4,9,10/6S/20E : 33/5S/20E									74,500	74.5	74.5	0.83	38.91
	1			FV	Solar	Solar	N/A	N/A	Unknown	Dec-20	Unknown	74,500	74.5	74.5	0.83	38.91
West County		FPL	Palm Beach County													
			29/43S/40E									4,047,000	4,047	3,771	4,047	3,771
	1			CC	NG	FO2	PL	TK	Unknown	Aug-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	2			CC	NG	FO2	PL	TK	Unknown	Nov-09	Unknown	1,349,000	1,349	1,257	1,349	1,257
	3			CC	NG	FO2	PL	TK	Unknown	May-11	Unknown	1,349,000	1,349	1,257	1,349	1,257
White Tail Solar [2/]		FPL	Martin County													
			27.080000, -80.379000									74,500	74.5	74.5	3.12	36.32
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-24	Unknown	74,500	74.5	74.5	3.12	36.32
Wild Azalea Solar [2/]		FPL NWFL	Gadsden County													
			30.6758,-84.74033									74,500	74.5	74.5	0.00	40.92
	1			FV	Solar	Solar	N/A	N/A	Unknown	Feb-23	Unknown	74,500	74.5	74.5	0.00	40.92
Wild Quail Solar [2/]		FPL NWFL	Walton County													
			30.898050, -86.250070									74,500	74.5	74.5	0.00	41.34
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	0.00	41.34
Wildflower Solar [2/]		FPL	Desoto County													
			25,26,/36S/25E									74,500	74.5	74.5	0.00	38.67
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jan-18	Unknown	74,500	74.5	74.5	0.00	38.67
Willow Solar [2/]		FPL	Manatee County													
			2,3,10,11/35S/22E									74,500	74.5	74.5	1.30	35.83
	1			FV	Solar	Solar	N/A	N/A	Unknown	Jul-21	Unknown	74,500	74.5	74.5	1.30	35.83
Woodyard Solar [2/]		FPL	Hendry County													
			26.420000, -81.051000									74,500	74.5	74.5	2.17	28.98
	1			FV	Solar	Solar	N/A	N/A	Unknown	Mar-24	Unknown	74,500	74.5	74.5	2.17	28.98
Total Nameplate System Generating Capacity as of December 31, 2024 [7/] =													**36,821**	**35,531**	-	-
Total Firm System Generating Capacity as of December 31, 2024 [8/] =													-	-	**29,878**	**31,691**

1/ These ratings are peak capability ratings for non-Solar units and Nameplate ratings for Solar units.

2/ These projected firm MW values represent the contribution of both non-solar and solar facilities at Summer and Winter Peak.

7/ The Total Nameplate System Generating Capacity value shown includes FPL-owned firm and non-firm generating capacity.

8/ The System Firm Generating Capacity value shown includes only firm generating capacity.

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CHAPTER II

Forecast of Electric Power Demand

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II. Forecast of Electric Power Demand

II.A. Overview of the Load Forecasting Process

The load forecasting team developed the forecasts of customers, sales, net energy for load (NEL), and peak demands presented in this 2025 Site Plan. The forecasts presented in this Site Plan were developed using consistent methodologies for both the FPL Legacy and FPL NWFL areas. These methodologies were also used to develop the forecasts previously presented in the four prior Site Plans. The load forecasting team continues to evaluate and implement appropriate enhancements to the forecasting methodologies for this and upcoming forecasts.

The long-term forecasts of customers, sales, NEL, and peak loads for the integrated system are developed annually. The forecasts for the integrated system for years 2025 and beyond were developed by combining the forecasts for the FPL Legacy and FPL NWFL areas. This is consistent with the forecasting methods employed for the prior three Site Plans. These forecasts are utilized throughout this 2025 Site Plan and are key inputs in the resource planning analyses that led to the integrated resource plans presented in this document.

The following pages describe how the forecasts of customers, sales, NEL, and peak loads were initially developed separately for the FPL Legacy and FPL NWFL areas and then combined into a single set of forecasts for the integrated system. This approach is because the historical data needed to develop the forecasts are for the legacy areas; historical data for the integrated system was not available when the forecasts were developed.

Similar to previous forecasts, the drivers for the forecasts include household growth, economic conditions, electricity prices, weather, and energy efficiency codes and standards. The forecasts for customers, energy sales, NEL, and summer peak demands are 50% probability (P50) forecasts, which means there is a 50% probability that actual results will be either higher or lower than the forecast.

The projections for population growth, household growth, and other economic variables are obtained from S&P Global, a leading economic forecasting firm that has been previously used by FPL. Additionally, the projections for electric vehicle adoption and impact come from Bloomberg New Energy Finance and Wood Mackenzie, while the projections for private solar adoption and impact are from Wood Mackenzie. Both Bloomberg and Wood Mackenzie are well known for their financial and energy forecasts. Using statistical models, these inputs are quantified in terms of their impact on the respective forecasts.

Weather is a key factor that affects energy sales and peak demand. The weather variables for use in the forecasting models are as follows:

1. The residential and commercial energy models incorporate heating degree hours and/or cooling degree hours. The threshold temperatures differ based on how each customer group responds to temperatures.
2. The Summer peak demand models incorporate minimum and maximum temperatures of the peak Summer day, while the Winter peak demand models incorporate minimum temperatures on the peak Winter day and the buildup of heating degree hours on the day prior to the peak day. Additional details are provided later in this chapter.

The weather variables used in the FPL models are based on a composite hourly temperature from the following weather stations: Miami, Fort Myers, Daytona Beach, and West Palm Beach. The temperatures for each weather station are weighted based on the energy sales associated with that region. The resulting composite temperatures are then used to derive the cooling degree hours and heating degree hours used in the energy models as well as the peak day temperatures used in the Summer and Winter peak demand models.

The weather variables used in the FPL NWFL models are based on the hourly temperatures from the Pensacola weather station. The Pensacola hourly temperatures are then used to derive the cooling degree hours and heating degree hours used in the energy models, the peak day cooling degree hours used in the Summer peak demand model, and the temperatures used in the Winter peak demand model.

II.B. Customer Forecasts

The customer forecasts for the integrated system for 2025 and beyond are the sum of the respective class-level customer forecasts for the FPL and FPL NWFL areas. The class-level customer forecasts were developed using a combination of regression models, exponential smoothing models, and inputs regarding wholesale contracts. The statistical models were developed using the software package MetrixND. The methods and tools used to develop the customer forecasts are consistent with those used for the prior four Site Plans, with routine updates to include additional historical data and updated economic projections, along with minor changes to model specifications.

The residential customer forecasts were developed using regression models which include households, lag dependent variables, and binary variables. The commercial customer models were segmented by rate code, and the models were a combination of regression models and exponential smoothing models. The commercial regression models included total non-agriculture employment for Florida, Florida Gross State Product, lagged dependent variables, and binary variables. The industrial customer models were also segmented by rate code, and the models were a combination of a regression model and exponential smoothing models. The industrial regression model included housing starts, lagged dependent variables, and a binary variable. The customer forecasts for the Metro and Other customer classes were developed by applying the last known value since little to no changes are expected in these customer classes. The Street & Highway Lighting forecast was developed by the lighting team. Resale (wholesale) customers were forecasted based on known or likely wholesale contracts.

Total customer growth is projected to grow at an average annual rate of 1.0% during the forecast period. The primary driver of customer growth is population growth.

II.C. Energy Sales Forecasts

Energy sales forecasts for the integrated system for 2025 and beyond are the sum of the respective class-level energy sales forecasts for the Legacy FPL and FPL NWFL areas. First, forecasts were developed for the major revenue classes, wholesale energy sales, and losses. Next, energy adjustments were calculated for factors, such as electric vehicles and private solar, and were applied to the class-level energy sales forecasts. Finally, these forecasts were then aggregated up to arrive at NEL forecasts (a bottom-up approach). The statistical models used in the energy sales forecasting process were developed using the software package MetrixND.

The methods and tools used to develop the energy sales forecasts were consistent with those used for the prior four Site Plans, with routine updates to include additional historical data and updated economic projections, along with minor updates to model specifications.

1. **Residential Sales**

The residential energy sales forecasts were developed using econometric models. Residential energy sales were first expressed as monthly use per customer per billing day. The forecasted energy use per customer per billing day was then multiplied by the projected number of billing days and customers to arrive at the residential billed energy sales forecast. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecast. The residential energy use per customer per billing day models include variables for cooling degree hours, heating degree hours, real wages per household, the moving average of real electricity price increases over time, energy savings from changes to energy efficiency codes and standards, binary variables, and autoregressive terms. The residential energy sales forecasts were also adjusted to reflect the anticipated impacts of continued adoption of electric vehicles and private solar.

2025 residential energy sales for the integrated system are projected to be 54.5% of sales to ultimate consumers and are projected to grow at an average annual rate of 1.5% over the forecast period.

2. **Commercial Sales**

The commercial energy sales forecasts were also developed using econometric models where the energy sales were expressed as monthly use per customer per billing day. The forecasted energy use per customer per billing day was multiplied by the projected number of billing days and customers to arrive at the commercial billed energy sales forecasts. The billed energy sales were then adjusted for unbilled energy to arrive at the calendar month delivered energy sales forecasts. The commercial energy use per customer forecasts were developed using separate models based on rate code. The two FPL models were for small/medium customers (commercial customers on energy only and demand rates less than 500 kilowatt) and large customers (commercial customers on demand rates of 500 kW or higher). The FPL NWFL models were for small customers (commercial customers on General Service or GS rates) and large customers (commercial customers on demand rates of 25 kW or higher). The commercial energy sales models utilize variables for cooling degree hours, heating degree hours, housing starts, employment, the moving average of real electricity price increases over time, energy savings from changes to energy efficiency codes and standards, binary variables, and autoregressive terms. The commercial lighting sales forecast was developed using inputs from FPL's lighting team. These forecasts are then added together to arrive at the total commercial sales forecast. The total commercial energy sales forecast was also adjusted to reflect the impacts of private solar.

2025 commercial energy sales for the integrated system are projected to be 41.4% of sales to ultimate consumers and are projected to grow at an average annual rate of 0.4% over the forecast period.

3. **Industrial Sales**

The projected industrial class energy sales were also forecasted using both econometric and exponential smoothing models. Industrial energy sales were expressed as either energy sales per customer or energy sales per customer per bill day. The resulting forecasts were then multiplied by bill days and/or customers to arrive at the billed energy sales forecasts. Energy usage for FPL's small and medium industrial customers (industrial customers on rate GS) was forecasted using an econometric model which included a lag dependent variable and binary variables while energy usage for large industrial customers were forecasted using an exponential smoothing model. FPL NWFL's industrial energy usage was forecasted using an exponential smoothing model. The industrial lighting sales forecast was developed using inputs from FPL's lighting team. These forecasts were then added together to arrive at the total industrial sales forecast. The total industrial sales forecast was adjusted to reflect the impact of very large demand, high load factor customers projected to take service on the FPL system during the planning period beginning in 2028.

For potential new customers with significant or unique load requirements, FPL's historical practice is to include the associated load in the forecast only after FPL and the customer have reached a definitive agreement or other binding commitment to extend service to the customer. At this time, there are no definitive agreements in place or other binding commitments between FPL and any large power users. However, based on discussions with potential large power users, such as a data centers, FPL believes there is a high probability for customers with significant load requirements to be served on the FPL system beginning in 2028 with total load growing to approximately 732 MW by 2033.

2025 industrial energy sales for the integrated system are projected to be 3.7% of sales to ultimate consumers and are projected grow at an average annual rate of 8.9% over the forecast period.

4. **Railroad & Railways Sales and Street and Highway Sales**

The Railroad & Railway class consists solely of Miami-Dade County's Metrorail system. The Railroad & Railways sales forecast was developed using a regression model which included monthly binary variables and autoregressive terms.

The forecast inputs for Street and Highway sales forecasts were provided by FPL's lighting team.

5. **Other Public Authority Sales**

This class consists of a sports field rate schedule (which is closed to new customers) and one governmental account. The forecast for this class was developed using an exponential smoothing model.

6. **Total Sales to Ultimate Customer**

The sales forecasts for each of the revenue classes were each summed to produce the Total Sales to Ultimate Customer forecasts.

7. **Sales for Resale**

Sales for Resale (wholesale) customers are comprised of sales to municipalities and/or electric co-operatives. These customers differ from jurisdictional customers in that they are not the ultimate users of electricity. Instead, they resell this electricity to their own customers.

The Sales for Resale forecast includes wholesale loads served under full and partial-requirements contracts that provide other utilities all, or a portion of, their load requirements at a level of service equivalent to FPL's own native load customers. There are currently twelve customers in this class: Florida Keys Electric Cooperative, Lee County Electric Cooperative, New Smyrna Beach, Wauchula, Homestead, Quincy, Moore Haven, Florida Public Utilities Company, Blountstown, Alachua, Jacksonville Electric Authority, and Bartow.

Since May 2011, FPL has provided service to the Florida Keys Electric Cooperative under a long-term, full-requirements contract which continues through 2032, with an option to extend the contract through 2052. The sales to Florida Keys Electric Cooperative are based on customer-supplied information and historical coincidence factors.

FPL sales to Lee County began in 2010. Lee County has a contract with FPL for the full requirements of their load, which began in 2014 and continues through 2033, with an option to extend the contract through 2053. Forecasted NEL for Lee County is based on customer-supplied information and historical usage trends.

FPL sales to New Smyrna Beach began in February 2014. The contract continues through December 2030. Under a second contract, additional sales to New Smyrna Beach began in

July 2017 and continues through December 2030. The two contracts have the option to be extended for three years through 2033.

FPL sales to Wauchula began in January 2024 and continue through December 2030.

FPL sales to Homestead began in August 2015. The contract continues through December 2028. Under a separate contract, additional sales to Homestead began in January 2020 and will continue through December 2028.

FPL sales to Quincy began in January 2016. The contract continues through December 2027.

FPL sales to Moore Haven began in July 2016. The contract continues through December 2025.

FPL began sales to Florida Public Utilities Company are under four contracts, with two that began sales in January 2018 and the other two that began in 2020. The contracts have been consolidated, with sales continuing through December 2029 with a four-year extension option.

FPL sales to Blountstown began in May 2022 and continue through April 2027.

FPL sales to Alachua began in April 2022 and continue through March 2029.

FPL sales to Jacksonville Electric Authority began in January 2022 and continue through December 2041.

FPL sales to Bartow began in January 2024 and continue through December 2030.

II.D. Net Energy for Load (NEL)

The NEL forecasts for the years 2025 through 2034 are the sums of the retail energy, wholesale energy, and losses forecasts. Through the use of the energy efficiency variable, the retail energy sales forecast includes the impacts from major energy efficiency codes and standards, including those associated with the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and savings resulting from the use of compact fluorescent lamps (CFL) and light emitting diodes (LED). The estimated impact from these codes and standards includes engineering estimates and any resulting behavioral changes. The impact of these savings began in 2005, and, from that year forward, their cumulative impact on NEL for the integrated system is projected to be a reduction of 9,645 GWh by 2034. This represents a 6.1% reduction in what the forecasted NEL for 2034 would have been absent these codes and standards. The incremental reduction from 2025 to 2034 is expected to be 2,460 GWh. The estimated impacts from codes and standards are based on the energy efficiency variables in the respective energy models. Collectively, this represents an extraordinary amount of energy efficiency on the integrated system. In addition, this energy efficiency is not funded through Energy Conservation Cost Recovery (ECCR) Clause rates paid by the general body of customers.

Adjustments were made to the NEL forecast to address the impact of incremental private (customer-owned) solar that is projected to be added during the forecast period. The impact of private solar on the NEL forecast for the integrated system is projected to be a reduction of approximately 9,300 GWh by 2034. Adjustments were also made for the additional load projected to be added due to the incremental adoption of new plug-in EVs. This results in an increase on the integrated system of approximately 12,000 GWh by 2034.

The combined NEL impacts of the adjustments for private solar and EV programs are an incremental net increase of almost 2,800 GWh by the end of the Site Plan forecast period, compared to the incremental net increase of approximately 2,000 GWh in the prior Site Plan. Although there was an increase in the impact of private solar, the substantial growth in the load additions from plug-in EVs more than offset the impact of load reductions due to private solar.

II.E. System Peak Forecasts

The rate of absolute growth in peak load is a function of the size of the customer base, projected economic conditions, and energy efficiency codes and standards. The peak load forecast models capture these behavioral relationships. The peak load forecasts also reflect changes in load from private solar, plug-in EVs, economic development riders, and wholesale requirements contracts.

The monthly peak loads for the integrated system from 2025 and beyond are the highest hourly demand from the forecasted system hourly load forecast, which was developed by first adjusting FPL NWFL's load to reflect Eastern time zone and then summing the forecasted system hourly loads for the systems. The integrated system peak load forecast reflects the growth in peak load and includes the expected reduction to the peak demand for the integrated system that results from load diversity.

When viewed as separate systems or regions, the loads peak at different times which results in load diversity, primarily due to the FPL NWFL system being located in a different time zone than the rest of the FPL system. The benefit of load diversity is a reduction to the integrated system peak demand. By 2034, the peak demand reductions from load diversity are projected to be 142 MW in the Summer and 543 MW in the Winter.

The savings from energy efficiency codes and standards incorporated into the peak forecast include the impacts from the 2005 National Energy Policy Act, the 2007 Energy Independence and Security Act, and the use of CFLs and LEDs. The impact from these energy efficiency standards began in 2005, and their cumulative reduction, from that year, on the integrated Summer peak is projected to reach approximately 8,100 MW by 2034. This reduction includes engineering estimates and any resulting behavioral changes.

For the integrated system, the cumulative 2034 impacts from these energy efficiency codes and standards are projected to effectively reduce the Summer peak by approximately 25% and the Winter peak by approximately 6% for that year. From the end of 2024 through 2034, the projected incremental impacts from these energy efficiency codes and standards are a reduction on the Summer peak of approximately 2,000 MW and a reduction on the Winter peak of approximately 520 MW.

As noted previously, the peak forecasts were also adjusted for the estimated load impacts from private solar and plug-in EVs. Plug-in EVs are projected to increase peak load on the integrated system by approximately 2,500 MW. in the Summer and 1,000 MW in the Winter by the end of 2034. Incremental additions of private solar on the integrated system are expected to decrease system peak load by approximately 2,240 MW in the Summer and 155 MW in the Winter by the end of 2034.

The forecasting methodologies for Summer, Winter, and monthly system peaks are discussed below.

1. **System Summer Peak**

The Summer peak demand forecast for the integrated system is the highest hourly demand during the Summer months from the integrated system hourly forecast which was developed by summing the forecasted system hourly loads for FPL and FPL NWFL. This approach ensures the Summer peak demand forecast for the integrated system reflects the growth in

Summer peak load while reflecting the previously mentioned peak demand reduction associated with load diversity. The Summer peak demand for the integrated system is projected to occur in August.

The Summer peak forecasts were developed using econometric models where the peak loads were expressed as Summer peak load per customer and the resulting projected peak loads per customer were multiplied by the forecast number of customers to arrive at the Summer peak load forecasts. The models included variables for weather, employment or income, and peak load reductions from change in energy efficiency codes and standards. The peak loads were then adjusted to account for the expected changes in loads resulting from private solar, plug-in EVs, and wholesale requirements contracts to derive FPL's system Summer peak.

2. **System Winter Peak**

The Winter peak forecast presented in this Site Plan is the highest hourly demand during the Winter months from the integrated system hourly forecast, which was developed by summing the forecasted system hourly loads for FPL and FPL NWFL. This approach ensures the Winter peak demand forecast for the integrated system reflects the growth in Winter peak while reflecting the Winter peak demand reduction associated with load diversity. The Winter peak demand for the integrated system is projected to occur in January.

FPL developed P50 normal weather Winter peak loads using two econometric models, one each for the FPL and FPL NWFL areas. The model for FPL expressed Winter peak load as peak load per customer and included weather variables, employment, and binary variables. The projected peak load per customer was multiplied by the customer forecast to arrive at the projected Winter peak load. The projections were then adjusted for the expected changes in loads resulting from private solar, plug-in EVs, and wholesale requirement contracts to arrive at the forecasted normal weather Winter peak load. The model for FPL NWFL expressed Winter peak load as peak load and included weather, population, and peak load reductions from changes in energy efficiency codes and standards. The projected load was then adjusted for the expected changes in loads resulting from private solar and plug-in EVs to arrive at the forecasted normal weather Winter peak load.

3. **Monthly Peak Forecasts**

The forecasting process for the monthly peaks assumes the Summer peak for FPL occurs in the month of August while the Summer peak for FPL NWFL occurs in the month of July. It also assumes that the Winter peak for both areas occur in the month of January. Finally, the remaining monthly peaks are forecasted based on the historical relationship between the monthly peaks and the annual Summer peak.

The monthly peak demand forecasts for the integrated system for 2025 and beyond are the highest hourly demand by month from the integrated system hourly forecasts. This approach ensures the integrated monthly peak demand forecast reflects the growth in monthly peaks as well as the monthly peak demand reductions associated with load diversity. The Summer peak for the integrated FPL system occurs in August because of the large size of the FPL Legacy area. The Winter peak for the integrated FPL system occurs in January.

II.F. Hourly Load Forecast

The forecasted values for system hourly load on the integrated system were the summation of the FPL Legacy and FPL NWFL hourly load for the period. The FPL NWFL system hourly load was adjusted from Central to Eastern time zone to be consistent with FPL Legacy's system hourly load.

Forecasted values for FPL's system hourly load were developed using a system load forecasting program named MetrixLT. This model uses years of historical FPL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of FPL's monthly peaks and energy.

Forecasted values for FPL NWFL's system hourly load were also developed using MetrixLT, which uses historical FPL NWFL hourly system load data to develop load shapes. The model generates a projection of hourly load values based on these load shapes and the forecast of FPL NWFL's monthly peaks and energy.

II.G. Uncertainty

Uncertainty is inherent in the load forecasting process. This uncertainty can result from a number of factors, including unexpected changes in consumer behavior, structural shifts in the economy, economic/business cycles, and fluctuating weather conditions. Large weather fluctuations can and frequently do result in significant deviations between actual and forecasted peak demands. In particular, Winter peak demands have experienced significantly greater volatility than those observed for the Summer peak or NEL.

The inherent uncertainty in load forecasting is addressed in different ways regarding the overall resource planning and operational planning work. With respect to resource planning work, the utilization of a 20% total reserve margin (TRM) criterion, a Loss-of-Load-Probability (LOLP) criterion of 0.1 days per year, and a 10% generation-only reserve margin (GRM) criterion are designed to maintain reliable electric service for customers in light of forecasting and other uncertainties. In addition, FPL's Winter peak demands have experienced significantly greater volatility than the Summer peak or NEL, and this greater volatility results in additional risks to FPL's ability to serve winter load. FPL continues to analyze system impacts of Winter peak demands due to this greater volatility. In addition, FPL's shift to stochastic LOLP modeling provides a look at a variety of different weather scenarios that affect FPL's demand throughout the year.

II.H. DSM

In this Site Plan, FPL accounts for the effects of its DSM energy efficiency programs through August 2024, which are embedded in the actual usage data for forecasting purposes. In addition, FPL accounts for the following projected DSM MW and MWh impacts as "line item reductions" to the forecasts as part of the IRP process: 1) the impacts of incremental energy efficiency that have been implemented after the 2024 Summer peaks have occurred, 2) projected impacts from incremental energy efficiency and load management, and 3) the impacts from previous signups in FPL's load management programs that will continue through 2034. After making these line-item adjustments to the load forecasted load values, the resulting "firm" load forecast, as shown in Chapter III in Schedules 7.1 and 7.2, is then used in the IRP work.

Historical and Forecast Load Information – Schedules 2-4

Schedules 2 through 4 below provide information regarding FPL's historical and forecasted load. Note that all historical information combines the load information of FPL and FPL NWFL.

Schedule 2.1
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			Commercial		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2015	10,758,616	2.33	64,232	4,618,890	13,906	51,263	587,965	87,186
2016	10,937,941	2.34	64,027	4,680,566	13,679	51,225	596,232	85,915
2017	11,075,378	2.34	63,373	4,740,017	13,370	50,951	604,336	84,309
2018	11,171,510	2.33	64,643	4,798,780	13,471	51,238	610,454	83,935
2019	11,256,787	2.30	65,872	4,886,791	13,480	51,857	622,212	83,344
2020	11,332,537	2.28	69,197	4,960,827	13,949	49,685	628,861	79,007
2021	11,441,385	2.27	67,162	5,036,950	13,334	50,506	636,044	79,407
2022	11,630,105	2.27	69,348	5,113,458	13,562	51,851	641,605	80,814
2023	11,827,634	2.28	70,206	5,179,816	13,554	52,507	642,772	81,689
2024	11,990,462	2.27	70,894	5,287,101	13,409	53,138	650,176	81,729

Historical Values (2015 - 2024):

Col. (2) represents population in the area served by the consolidated system.

Col. (4) and Col. (7) represent actual energy sales including the impacts of existing conservation.
These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.1
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
			Rural & Residential			**Commercial**		
Year	Population	Members per Household	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	Average No. of Customers	Average kWh Consumption Per Customer
2025	12,228,942	2.28	69,688	5,355,964	13,011	52,838	657,928	80,310
2026	12,426,323	2.29	70,291	5,420,089	12,969	53,168	665,449	79,899
2027	12,554,958	2.29	70,778	5,483,159	12,908	53,260	672,449	79,203
2028	12,656,294	2.28	71,742	5,543,418	12,942	53,598	679,113	78,923
2029	12,759,832	2.28	72,777	5,600,718	12,994	53,921	685,631	78,645
2030	12,865,517	2.27	73,793	5,656,354	13,046	54,126	691,983	78,218
2031	12,973,547	2.27	75,012	5,711,056	13,134	54,311	697,995	77,809
2032	13,082,486	2.27	76,510	5,764,905	13,272	54,475	703,883	77,393
2033	13,191,965	2.27	77,954	5,817,992	13,399	54,556	709,638	76,878
2034	13,300,596	2.27	79,392	5,870,592	13,524	54,566	715,294	76,285

Projected Values (2025 - 2034):

Col. (2) represents population in the area served by the consolidated system.

Col. (4) and Col. (7) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (5) and Col. (8) represent the annual average of the twelve monthly values.

Schedule 2.2
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads & Railways	Street & Highway Lighting	Sales to Public Authorities	Sales to Ultimate Consumers
Year	GWh	Average No. of Customers	Average kWh Consumption Per Customer	GWh	GWh	GWh	GWh
2015	4,849	11,560	419,443	92	473	23	120,931
2016	4,892	12,012	407,231	92	472	23	120,730
2017	4,693	11,904	394,249	83	473	41	119,614
2018	4,770	11,850	402,549	80	473	23	121,227
2019	4,759	12,043	395,169	82	456	23	123,050
2020	4,749	12,239	388,022	71	445	20	124,166
2021	4,721	12,785	369,236	68	433	19	122,908
2022	4,714	14,094	334,458	71	427	39	126,450
2023	4,617	15,625	295,521	67	420	86	127,904
2024	4,841	15,160	319,325	67	417	29	129,386

Historical Values (2015 - 2024):

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) represents actual energy sales including the impacts of existing conservation. These values are at the meter.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.2
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Industrial			Railroads	Street &	Sales to	Sales to
		Average	Average kWh	&	Highway	Public	Ultimate
		No. of	Consumption	Railways	Lighting	Authorities	Consumers
Year	GWh	Customers	Per Customer	GWh	GWh	GWh	GWh
2025	4,724	15,748	299,944	68	413	23	127,754
2026	4,735	15,713	301,325	68	376	23	128,661
2027	4,739	15,729	301,312	68	354	23	129,222
2028	6,026	15,822	380,856	68	345	23	131,801
2029	7,313	15,966	458,060	68	339	23	134,441
2030	8,600	16,093	534,419	68	338	23	136,948
2031	9,141	16,156	565,774	68	338	23	138,892
2032	9,679	16,125	600,236	68	338	23	141,092
2033	10,214	15,984	638,985	68	338	23	143,152
2034	10,210	15,751	648,203	68	338	23	144,597

Projected Values (2025 - 2034):

Col. (10) and Col.(15) represent forecasted energy sales that do not include the impact of incremental conservation. These values are at the meter.

Col. (11) represents the annual average of the twelve monthly values.

Col. (16) = Schedule 2.1 Col. (4) + Schedule 2.1 Col. (7) + Col. (10) + Col. (13) + Col. (14) + Col. (15).

Schedule 2.3
History of Energy Consumption
And Number of Customers by Customer Class

(1)	(17)	(18)	(19)	(20)	(21)
Year	Sales for Resale GWh	Utility Use & Losses GWh	Net Energy For Load GWh	Average No. of Other Customers	Total Average Number of Customers
2015	6,926	6,895	134,752	4,517	5,222,932
2016	6,937	5,981	133,649	4,603	5,293,413
2017	6,711	6,136	132,460	4,674	5,360,931
2018	7,089	6,188	134,504	4,923	5,426,008
2019	7,616	6,499	137,165	5,357	5,526,403
2020	8,503	6,514	139,183	5,743	5,607,670
2021	7,060	6,800	136,768	6,153	5,691,932
2022	8,476	5,990	140,916	6,687	5,775,844
2023	8,167	7,684	143,756	6,947	5,845,160
2024	8,923	7,794	146,103	7,314	5,959,751

Historical Values (2015 - 2024):

Col. (19) represents actual energy sales including the impacts of existing conservation.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18). Historical NEL includes the impacts of existing conservation and agrees to Col. (5) on schedule 3.3.

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8)
+ Schedule 2.2 Col. (11) + Col. (20).

Schedule 2.3
Forecast of Energy Consumption
And Number of Customers by Customer Class

(1) Year	(17) Sales for Resale GWh	(18) Utility Use & Losses GWh	(19) Net Energy For Load GWh	(20) Average No. of Other Customers	(21) Total Average Number of Customers
2025	8,662	8,377	144,793	7,842	6,037,481
2026	8,666	7,604	144,931	8,433	6,109,683
2027	8,660	8,023	145,905	8,826	6,180,163
2028	8,588	8,172	148,562	9,025	6,247,378
2029	8,264	8,272	150,976	9,230	6,311,545
2030	7,771	8,374	153,094	9,452	6,373,882
2031	7,046	8,437	154,375	9,554	6,434,761
2032	7,018	8,618	156,728	9,554	6,494,467
2033	7,041	8,729	158,922	9,554	6,553,168
2034	7,063	8,814	160,473	9,554	6,611,191

Projected Values (2025 - 2034):

Col. (19) represents forecasted energy sales that do not include the impact of incremental conservation and agrees to Col. (2) on Schedule 3.3.

Col. (19) = Schedule 2.2 Col. (16) + Col. (17) + Col. (18).

Col. (20) represents the annual average of the twelve monthly values.

Col. (21) = Schedule 2.1 Col. (5) + Schedule 2.1 Col. (8)
+ Schedule 2.2 Col. (11) + Col. (20).

Schedule 3.1
History of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2015	25,361	1,381	23,980	0	878	1,779	826	1,104	23,657
2016	26,044	1,443	24,601	0	882	1,809	836	1,119	24,326
2017	25,662	1,467	24,194	0	910	1,826	825	1,135	23,927
2018	25,411	1,418	23,993	0	866	1,839	866	1,149	23,679
2019	26,594	1,367	25,227	0	852	1,850	879	1,159	24,863
2020	26,400	1,595	24,805	0	845	1,861	887	1,175	24,668
2021	26,248	1,401	24,847	0	830	1,874	882	1,190	24,536
2022	26,429	1,572	24,857	0	827	1,886	871	1,201	24,731
2023	28,461	1,652	26,808	0	797	1,900	946	1,210	26,718
2024	28,266	1,731	26,535	0	863	1,917	961	1,221	26,442

Historical Values (2015 - 2024):

Col. (2) and Col. (3) are actual values for historical Summer peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.1
Forecast of Summer Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
August of Year	Total	Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2025	28,312	1,728	26,584	0	937	21	1,025	12	26,317
2026	28,664	1,727	26,937	0	925	40	1,032	19	26,648
2027	28,925	1,723	27,202	0	913	59	1,038	26	26,888
2028	29,333	1,708	27,625	0	902	77	1,043	34	27,277
2029	29,687	1,606	28,081	0	896	95	1,047	41	27,608
2030	29,982	1,484	28,498	0	893	113	1,051	49	27,877
2031	30,301	1,315	28,987	0	891	131	1,055	57	28,168
2032	30,823	1,319	29,504	0	889	148	1,059	65	28,662
2033	31,257	1,323	29,934	0	888	166	1,063	73	29,068
2034	31,677	1,327	30,351	0	887	183	1,067	81	29,459

Projected Values (2025 - 2034):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected August values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.2
History of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management	Residential Conservation	C/I Load Management	C/I Conservation	Net Firm Demand
2015	21,961	1,403	20,558	0	822	1204	551	522	20,588
2016	18,826	1,167	17,659	0	742	1232	570	528	17,514
2017	19,320	1,187	18,133	0	759	1238	577	541	17,984
2018	21,533	1,332	20,201	0	750	1244	588	547	20,194
2019	17,941	1,498	16,442	0	706	1248	613	557	16,621
2020	19,569	1,312	18,257	0	702	1253	614	568	18,253
2021	17,486	1,344	16,142	0	689	1256	619	580	16,178
2022	21,027	1,230	19,797	0	681	1258	628	584	19,718
2023	19,271	1,214	18,057	0	670	1263	631	589	17,970
2024	18,595	1,093	17,502	0	743	1,272	657	597	17,195

Historical Values (2015 - 2024):

Col. (2) and Col. (3) are actual values for historical Winter peaks. As such, they incorporate the effects of conservation (Col. 7 & Col. 9) and may incorporate the effects of load control if load control was operated on these peak days. Col. (2) represents the actual Net Firm Demand.

Col. (5) through Col. (9) represent actual DSM capabilities and represent annual (12-month) values.

Col. (10) represents a hypothetical "Net Firm Demand" as if the load control values had definitely been exercised on the peak.
Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col.(6) + Col. (8).

Schedule 3.2
Forecast of Winter Peak Demand (MW)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
January of Year	Total	Firm Wholesale	Retail	Interruptible	Res. Load Management*	Residential Conservation	C/I Load Management*	C/I Conservation	Net Firm Demand
2025	23,042	1,375	21,667	0	778	12	717	7	21,527
2026	23,323	1,377	21,946	0	766	23	722	12	21,800
2027	23,648	1,380	22,268	0	754	35	727	17	22,116
2028	24,136	1,364	22,772	0	742	46	732	22	22,594
2029	24,603	1,313	23,290	0	731	57	735	27	23,053
2030	25,011	1,216	23,795	0	726	68	739	32	23,446
2031	25,384	1,140	24,244	0	721	79	742	37	23,804
2032	25,852	1,144	24,707	0	716	90	746	43	24,256
2033	26,245	1,149	25,096	0	712	102	749	48	24,634
2034	26,638	1,153	25,485	0	708	113	752	54	25,011

Projected Values (2025 - 2034):

Col. (2) - Col. (4) represent forecasted peak and do not include incremental conservation, cumulative load management, or incremental load management.

Col. (5) through Col. (9) represent cumulative load management, incremental conservation, and load management.
All values are projected January values.

Col. (8) represents FPL's Business On Call, CDR, CILC, and curtailable programs/rates.

Col. (10) represents a "Net Firm Demand" which accounts for all of the incremental conservation and assumes all of the load control is implemented on the peak. Col. (10) is derived by the formula: Col. (10) = Col. (2) - Col. (5) - Col. (6) - Col. (7) - Col. (8) - Col. (9).

* Res. Load Management and C/I Load Management include Lee County and FKEC whose loads are served by FPL.

Schedule 3.3
History of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Year	Net Energy For Load without DSM GWh	Residential Conservation GWh	C/I Conservation GWh	Actual Net Energy For Load GWh	Sales for Resale GWh	Utility Use & Losses GWh	Actual Total Retail Sales (GWh)	Load Factor(%)
2015	141,611	3,862	2,997	134,752	6,926	6,895	120,931	60.7%
2016	140,578	3,891	3,038	133,649	6,937	5,981	120,730	58.4%
2017	139,467	3,920	3,088	132,460	6,711	6,136	119,614	58.9%
2018	141,604	3,947	3,153	134,504	7,089	6,188	121,227	60.4%
2019	144,323	3,972	3,186	137,165	7,616	6,499	123,050	58.9%
2020	146,397	3,995	3,219	139,183	8,503	6,514	124,166	60.0%
2021	144,025	4,021	3,236	136,768	7,060	6,800	122,908	59.5%
2022	148,226	4,057	3,253	140,916	8,476	5,990	126,450	60.9%
2023	151,150	4,091	3,303	143,756	8,167	7,684	127,904	57.7%
2024	153,582	4,140	3,339	146,103	8,923	7,794	129,386	58.8%

Historical Values (2015 - 2024):

Col. (2) represents derived NEL not including conservation using the formula: Col. (2) = Col. (3) + Col. (4) + Col. (5)

Col. (3) & Col. (4) are annual (12-month) DSM values and represent total GWh reductions experienced each year.

Col. (8) is the Total Retail Sales calculated using the formula: Col. (8) = Col. (5) - Col. (6) - Col. (7). These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and the greater of Col. (2) from Schedules 3.1 and 3.2 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 3.3
Forecast of Annual Net Energy for Load (GWh)
(All values are "at the generator" values except for Col (8))

(1) Year	(2) Forecasted Net Energy For Load without DSM GWh	(3) Residential Conservation GWh	(4) C/I Conservation GWh	(5) Net Energy For Load Adjusted for DSM GWh	(6) Sales for Resale GWh	(7) Utility Use & Losses GWh	(8) Forecasted Total Billed Retail Energy Sales w/o DSM GWh	(9) Load Factor(%)
2025	144,793	75	69	144,649	8,662	8,377	127,754	58.3%
2026	144,931	126	118	144,687	8,666	7,604	128,661	57.6%
2027	145,905	176	168	145,561	8,660	8,023	129,222	57.4%
2028	148,562	225	219	148,118	8,588	8,172	131,801	57.5%
2029	150,976	273	270	150,433	8,264	8,272	134,441	57.8%
2030	153,094	322	322	152,449	7,771	8,374	136,948	58.0%
2031	154,375	371	375	153,629	7,046	8,437	138,892	57.9%
2032	156,728	419	429	155,880	7,018	8,618	141,092	57.6%
2033	158,922	468	483	157,971	7,041	8,729	143,152	57.7%
2034	160,473	515	539	159,419	7,063	8,814	144,597	57.5%

Projected Values (2025 - 2034):

Col. (2) represents Forecasted NEL and does not include incremental conservation. It is the summation of Cols. (3) through (5).

Col. (3) & Col. (4) are forecasted values representing reduction on sales from incremental conservation

Col. (5) is forecasted NEL and includes incremental conservation as well company use and losses.

Col. (8) is Total Retail Sales. The values are calculated using the formula: Col. (8) = Col. (2) - Col. (6) - Col. (7).
These values are at the meter.

Col. (9) is calculated using Col. (5) from this page and Col. (10) from Schedule 3.1 using the formula:
Col. (9) = ((Col. (5)*1000) / ((Col. (2) * 8760). Adjustments are made for leap years.

Schedule 4
Previous Year Actual and Two-Year Forecast of
Total Peak Demand and Net Energy for Load (NEL) by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2024 ACTUAL		2025 FORECAST		2026 FORECAST	
Month	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh	Total Peak Demand MW	NEL GWh
JAN	18,595	10,188	23,042	10,542	23,323	10,352
FEB	18,147	9,124	21,421	9,694	21,702	9,820
MAR	20,596	10,676	21,414	10,598	21,691	10,713
APR	21,148	10,783	22,918	11,142	23,211	11,178
MAY	26,889	14,122	25,189	12,760	25,503	12,751
JUN	27,296	13,848	27,189	13,506	27,523	13,559
JUL	27,722	15,298	27,656	14,484	28,006	14,535
AUG	28,266	14,957	28,312	14,663	28,664	14,636
SEP	26,477	14,014	27,191	13,478	27,531	13,488
OCT	26,287	12,059	25,394	12,571	25,711	12,464
NOV	19,524	10,933	22,162	10,605	22,447	10,626
DEC	18,408	10,101	20,935	10,751	21,211	10,807
Annual Values:		**146,103**		**144,793**		**144,931**

Col. (3) annual value shown is consistent with the value shown in Col.(5) of Schedule 3.3.

Cols. (4) through (7) do not include the impacts of cumulative load management, incremental utility conservation, or incremental load management.

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CHAPTER III

Projection of Incremental Resource Additions

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III. Projection of Incremental Resource Additions

III.A. FPL's Resource Planning:

FPL utilizes its well-established, but continually evolving integrated resource planning (IRP) process, in whole or in part as dictated by analysis needs, to determine: (i) the magnitude and timing of needed resources, and (ii) the type of resources that should be added. This section describes FPL's basic IRP process which was used during 2024 and early 2025 to develop the resource plans for FPL's system that are presented in this 2025 Site Plan. It also discusses some of the key assumptions, in addition to a new load forecast discussed in the previous chapter, which were used in developing this resource plan.

Four Fundamental Steps of FPL's Resource Planning:

The four fundamental steps of FPL's resource planning process are:

Step 1: Determine the magnitude and timing of FPL's new resource needs;

Step 2: Identify which resource options and resource plans can meet the determined magnitude and timing of projected resource needs (*e.g.*, identify competing options and resource plans);

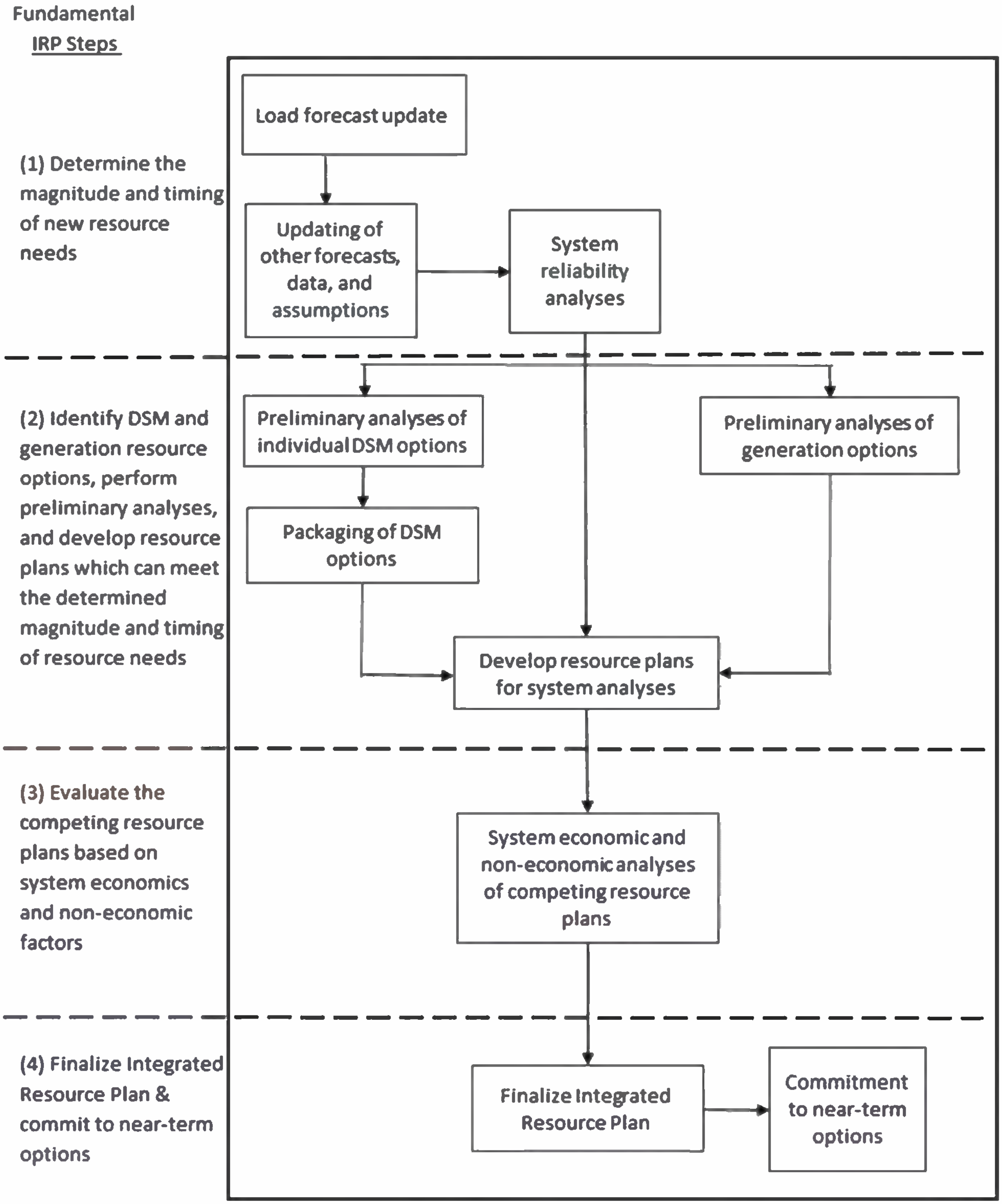
Step 3: Evaluate the competing options and resource plans based on system economics and non-economic factors; and,

Step 4: Select a resource plan and commit, as needed, to near-term options.

Figure III.A.1 graphically outlines the 4 steps.

Overview of IRP Process: Fundamental Steps

Figure III.A.1: Overview of IRP Process



Step 1: Determine the Magnitude and Timing of New Resource Needs:

The first of the four resource planning steps is essentially a determination of the amount and timing of MW load reduction, new capacity additions, or a combination of both, which are needed to maintain and/or enhance system reliability. This step is often referred to as a reliability assessment for the utility system.

This analysis typically starts with an updated load forecast. Several databases are also updated in this first fundamental step, not only with the new information regarding forecasted loads, but also with other information that is used throughout other aspects of FPL's resource planning process. Examples of this new information include: delivered fuel price projections, current financial and economic assumptions, current power plant capability and operating assumptions, costs of new resource additions, and current DSM demand and energy reduction assumptions.

FPL's process also includes key sets of projections regarding three specific types of resources: (1) generating unit capacity changes, (2) firm capacity PPAs, and (3) DSM implementation.

Key Assumptions Regarding the Three Types of Resources:

Generating Unit Capacity Additions:

The first set of assumptions, generating unit capacity changes, is based on current projections of new generating capacity additions and planned retirements of existing generating units. In this 2025 Site Plan, there are four types of projected generation capacity changes through the ten-year reporting time frame of this document. These changes are listed below in general chronological order:

1. Additional Solar Energy Facilities:

In this 2025 Site Plan, the resource plan projects the addition of approximately 17,433 MW of new solar PV generation during the 2025-2034 period. These PV additions are projected to be sited throughout FPL's service area. These projected solar additions for 2025-2034, when combined with solar additions made prior to 2025, will result in a total of approximately 24,471 MW of total installed utility PV by the end of 2034.

All PV projected to be added from 2025-2034 are "tracking" solar. In fixed-tilt solar configurations, the solar panels remain facing the same angle, while tracking solar changes the angle of the solar panels to follow the path of the sun during the day, generally resulting in greater annual energy production, which allows for a greater customer benefit from fuel savings and production tax credits.

2. Additional Battery Storage:

At the end of 2021, a battery storage facility with a projected maximum output of 409 MW was placed in-service at the existing Manatee plant site. This large battery storage facility is charged by solar energy from an existing nearby PV facility. Two 30 MW battery storage facilities were installed at two different locations in the FPL service area and put into service at the end of 2021. Both 30 MW battery storage facilities are also charged by existing solar facilities. In addition, the resource plan presented in this Site Plan projects that an additional 7,603 MW of battery storage facilities will be installed by 2034 throughout FPL's service area.

3. Retirement of Existing Generating Units:

The resource plan for the 2025 TYSP reflects the retirements of two units: Gulf Clean Energy Center Units 4 & 5. These units will be retired at the end of 2029. In the 2024 TYSP, FPL had previously reflected the retirement of its 25% ownership share (215 MW) in the coal-fueled Scherer Unit 3 in Georgia at the end of 2028. As a result of the primary owner of Unit 3, Georgia Power, amending its retirement date for Scherer Unit 3, FPL has had to follow suit and push out its retirement date for its interest in that unit to outside of the ten-year period of this Site Plan.

4. Enhancements of Existing Generating Units:

In its 2024 Site Plan, FPL discussed plans to upgrade the CT components in several of FPL's existing CC units. That upgrade effort is still included in the resource plan presented in this Site Plan. These additional upgrades are projected to be completed by 2028. Information regarding the specific units, timing, and magnitude of these upgrades is presented in Schedule 8 in this chapter.

In addition, FPL implemented a pilot project that results in hydrogen replacing a portion of the natural gas that is currently being used to fuel the existing Okeechobee CC unit. In this pilot project, hydrogen is created by using solar energy, or other energy from the electric grid, to power an electrolyzer that separates water into hydrogen and oxygen (If the hydrogen is created using only solar or other renewable energy sources, the hydrogen is referred to as "green" hydrogen). The resulting hydrogen is then stored in on-site tanks until it is used as a fuel. The objective of the pilot project is to test, in practice, the concept of blending natural gas with hydrogen as a fuel for CC unit use. This pilot project went into service in late 2023.

Firm Capacity PPAs:

The second set of assumptions involves other firm capacity PPAs. These assumptions are generally consistent with those presented in FPL's 2024 Site Plan.

The remaining projected firm capacity purchases are from independent power producers. Details for these other purchases, including the annual total capacity values, are presented in Chapter I in Tables I.A.3.2 and I.A.3.3. These purchased firm capacity amounts were incorporated in the resource planning work that led to the resource plan presented in this document.

DSM Implementation:

The third set of assumptions involves a projection of the amount of incremental DSM that FPL anticipates implementing annually over the ten-year reporting period of 2025-2034 for this Site Plan. In April of 2024, FPL filed its proposed 2024 DSM Goals. These Goals were approved by the FPSC and FPL filed a plan to meet these goals in March 2025. This plan accounts for the projected annual amounts of Summer MW reduction, Winter MW reduction, and energy (MWh) reduction for the years 2025-2034.

The Three Reliability Criteria Used to Determine FPL's Projected Resource Needs:

FPL's resource planning process applies these key assumptions, plus the other updated information described above, in the first fundamental step: determining the magnitude and timing of future resource needs. This determination is accomplished through system reliability analyses. Until 2014, FPL's reliability analyses were based on dual planning criteria, including a minimum peak-period total reserve margin (TRM) of 20% (FPL applies this criterion to both Summer and Winter peaks) and a maximum LOLP of 0.1 day per year. Both criteria are commonly used throughout the utility industry. Beginning in 2014, FPL began utilizing a third reliability criterion: a 10% GRM.

These reliability criteria utilize two basic types of methodologies: deterministic and probabilistic. The calculation of excess firm capacity at the annual system peaks (reserve margin) is a common method, and this relatively simple deterministic calculation can be performed on a spreadsheet. It provides an indication of the adequacy of a generating system's capacity resources compared to its load during peak periods. However, deterministic methods do not take into account probabilistic-related elements, such as the impact of individual unit failures. For example, two 50 MW units that can be counted on to run 90% of the time are more valuable in regard to utility system reliability than is one 100 MW unit that also can be counted on to run 90% of the time. Probabilistic methods can also account for the value of being part of an interconnected system with access to multiple capacity sources.

For this reason, probabilistic methodologies have been used to provide an additional perspective on the reliability of a generating system and are used to perform system reliability analyses. Among the most widely used is LOLP, which FPL's resource planning group utilizes. Simply stated, LOLP is an index of how well a generating system may be able to meet its firm demand (*i.e.*, a measure of how often load may exceed available resources). In contrast to reserve margin, the calculation of LOLP looks at the daily peak demands for each year, while taking into consideration such probabilistic events as the unavailability of individual generators due to scheduled maintenance or forced outages.

LOLP is expressed in terms of the projected probability that a utility will be unable to meet its entire firm load at some point during a year. The probability of not being able to meet the firm load is calculated for each day of the year using the daily peak hourly load. These daily probabilities are then summed to develop an annual probability value. This annual probability value is commonly expressed as "the number of days per year" that the system firm load could not be met. The standard for LOLP used by FPL's resource planning group is a maximum of 0.1 day per year which is commonly accepted throughout the industry. This analysis requires a more complicated calculation methodology than the reserve margin analysis. LOLP analyses are typically carried out using computer software models, such as the Tie Line Assistance and Generation Reliability (TIGER) program used by FPL.

Recently, FPL has expanded usage of its LOLP criterion by utilizing a stochastic approach to LOLP modeling. As FPL's system continues to incorporate additional cost-effective intermittent solar generation, the Company is continuing to adapt its resource planning to ensure that customers' reliability needs are met through available, dispatchable resources that provide value to customers. Just as FPL's system has advanced and modernized over time, resource adequacy must also be modernized to consider evolving conditions that affect the delivery of power in times of greatest need. To that end, FPL retained an independent third-party consulting firm, E3 Consulting, to perform a comprehensive, stochastic LOLP analysis to ensure that FPL's proposed system additions optimally address system needs for each hour of the year.

FPL's incorporation of cost-effective solar has increased to the extent that the peak hour of the year – i.e., the hour of greatest demand on the system – is no longer the most critical hour for determining reliability need. Now, the most critical time for capacity on FPL's system is at peak net demand, which most often occurs between 5:00 p.m. and 8:00 p.m., when solar facilities are providing less generation output. For these hours, as well as all other hours throughout the year, FPL needs additional, more modernized modeling analysis to determine its resource adequacy and identify where its greatest resource needs lie. Thus, for its 2025 resource planning, FPL added a stochastic LOLP analysis tailored to its system to identify (1) hourly periods of the year where there is increased likelihood for a loss of load, and (2) available resources that can remediate the potential for that loss.

Stochastic LOLP modeling incorporates vast amounts of data to develop a granular view of a utility's system adequacy in hour-by-hour segments. This modeling incorporates significantly more data in assessing system reliability than a traditional LOLP analysis, providing a substantially wider range of load and generation conditions across numerous scenarios. Through this analysis, a utility can more effectively determine the sufficiency of its hourly generation supply throughout the year, which, in turn, allows it to identify any needed system additions.

The stochastic LOLP analysis incorporates a tremendous amount of system-specific data required to develop a probabilistic hourly load and supply projection and identify the system's reliability needs. In comparison, a traditional reserve margin analysis provides a more limited and simplified look at system operations, examining only the peak demand hour at two times of the year – once in the winter and once in the summer – without considering the unique generation attributes of the utility's fleet. The traditional reserve margin analysis therefore carries analytical shortcomings, particularly for systems that incorporate substantial renewable generation. For example, as FPL's solar generation portfolio has increased, the hours of the day with the least reserves are more likely to be found in the evening as the sun begins to set and solar generation decreases. The traditional reserve margin analysis does not fully reflect this more recent trend. The traditional reserve margin analysis also fails to capture the interactive effects of non-dispatchable generation and load, which have become increasingly challenging to predict and model. The stochastic LOLP analysis addresses these shortcomings by accounting for and modeling these factors, assessing resource availability at every hour of the year and identifying the periods when reserves are most depleted, wherever they may fall.

The stochastic modeling also presents a more sophisticated analysis than FPL's prior LOLP analyses. A traditional LOLP analysis models expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages. The stochastic LOLP analysis, however, simulates a random selection of plant outages, which better reflects the unpredictable nature of unavailable generation as observed in normal system operations. Additionally, a traditional LOLP analysis models an expected solar generation profile, whereas the stochastic LOLP analysis produces a reliability assessment that captures the natural variability in solar production due to weather conditions. The stochastic LOLP model also better captures the synergistic interactions between load and non-dispatchable generation because it models the variability of each input separately.

For FPL's 2025 planning, the consulting firm E3 coordinated with FPL and used hourly temperature data from representative weather stations to develop hourly load profiles using a machine learning algorithm trained on actual load and temperatures from 2003 to 2023. E3 also used historic satellite data to simulate hourly solar generation at each of the current and future solar generating sites for the 1980 to 2023 period, as well as actual historical generating unit availability data to calculate an expected forced outage rate and a mean time to repair for every generating unit in the FPL fleet. The model used these inputs to randomly select which units may experience an outage at any given time within the simulations. FPL has incorporated the results of this study to produce the resource plan in this Site Plan and will continue to examine stochastic LOLP studies to accentuate future resource planning efforts.

FPL's third reliability criterion, the 10% minimum Summer and Winter GRM criterion, augments the other two reliability criteria by providing an indication of the respective roles that DSM and generation are projected to play each year as FPL maintains its 20% Summer and Winter TRMs (which account for both generation and DSM resources). All three reliability criteria are useful to identify the timing and magnitude of the resource needs because of the different perspectives the three criteria provide. In addition, the GRM criterion is particularly useful in providing direction regarding the mix of generation (solar, battery storage, etc.) and DSM resources that should be added to maintain and enhance system reliability.

Step 2: Identify Resource Options and Plans That Can Meet the Determined Magnitude and Timing of Projected Resource Needs:

The initial activities associated with this second fundamental step of resource planning generally proceed concurrently with the activities associated with Step 1. During Step 2, preliminary economic screening analyses of new capacity options that are identical, or virtually identical, in certain key characteristics may be conducted to determine what type of new capacity option appears to be the most competitive on FPL's system. Preliminary analyses also can help identify capacity size (MW) values, projected construction/permitting schedules, and operating parameters and costs. Similarly, preliminary economic screening analyses of new DSM options and/or evaluation of existing DSM options are often conducted in this second fundamental IRP step when FPL is determining its DSM goals.

FPL's resource planning group typically utilizes an optimization model to perform the preliminary economic screening of generation resource options. For the preliminary economic screening analyses of DSM resource options, FPL typically uses its DSM Conservation, Planning, and Forecasting (CPF) model, which is an FPL spreadsheet model utilizing the FPSC's approved methodology for performing preliminary economic screening of individual DSM measures and programs. Then, as the focus of DSM analyses progresses from analysis of individual DSM measures to the development of DSM portfolios, FPL typically uses two additional models. One is a proprietary non-linear programming (NLP) model that is used to analyze the potential for lowering system peak loads through additional load management/demand response capability. The other model that is utilized is a proprietary linear programming (LP) model with which DSM portfolios are developed.

The next step is typically to "package" the individual new resource options, both Supply options and DSM portfolios, emerging from these preliminary economic screening analyses into different resource plans that are designed to meet the system reliability criteria. In other words, resource plans are created by combining individual resource options so that the timing and magnitude of projected new resource needs are met. The creation of these competing resource plans is typically carried out using spreadsheet and/or dynamic programming techniques.

At the conclusion of the second fundamental resource planning step, different combinations of new resource options (*i.e.*, resource plans) of a magnitude and timing necessary to meet the projected resource needs are identified.

Step 3: Evaluate the Competing Options and Resource Plans Based on System Economics and Non-Economic Factors:

At the completion of fundamental Steps 1 and 2, the most viable new resource options have been identified, and these resource options have been combined into resource plans that each meet the magnitude and timing of projected resource needs. The stage is set for evaluating these resource options and resource plans in system economic analyses that aim to account for all the impacts to the utility system from the competing resource options/resource plans. FPL's resource planning group typically utilizes the AURORA optimization model to develop and perform the system economic analyses of resource plans. Other spreadsheet models may also be used to further analyze the resource plans.

The basic economic analyses of the competing resource plans focus on total system economics. The standard basis for comparing the economics of competing resource plans is their relative impact on electricity rate levels, with the general objective of minimizing the projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM methodology). In analyses in which the DSM contribution has already been determined through the same IRP process and/or FPSC approval, and therefore the only competing options are new generating units and/or purchase options, comparisons of the impacts of competing resource plans on both electricity rates and system revenue requirements will yield identical outcomes in regard to the relative rankings of the resource options being evaluated. Consequently, the competing options and resource plans in such cases can be evaluated on a system cumulative present value revenue requirement (CPVRR) basis.

FPL's resource planning group also includes other factors in its evaluation of resource options and resource plans. Although these factors may have an economic component or impact, they are often discussed in quantitative but non-economic terms, such as percentages, tons, etc., rather than in terms of dollars. These factors are often referred to as "system concerns or factors," which include reducing emissions, maintaining/enhancing fuel diversity, and maintaining a regional balance between load and generating capacity, particularly in the Southeastern region of FPL's area that consists of Miami-Dade and Broward counties. In conducting the evaluations needed to determine which resource options and resource plans are best for the utility system, the non-economic evaluations are conducted with an eye to whether the system concern is positively or negatively impacted by a given resource option or resource plan. These and other factors are discussed later in this chapter in section III.C.

Step 4: Finalizing the Current Resource Plan

The results of the previous three fundamental steps are typically used to develop a new or updated resource plan. The current resource plan presented in this 2025 Site Plan is summarized in the following section.

III.B. Projected Incremental Resource Changes in the Resource Plan

The projection of major changes in the resource plan, including both utility-owned generation and PPAs, for the years 2025-2034 is summarized in Table ES-1 in the Executive Summary. In regard to DSM additions, all of the DSM presented in this Site Plan represents FPL's DSM through the end of 2034. Those annual amounts are shown in Schedules 3.1, 3.2, and 3.3 in Chapter II.

A summary of some of the larger resource additions/retirements include those listed below :

- New solar (PV) additions from 2025 through 2034 of approximately 17,433 MW (nameplate);
- A total addition of approximately 7,603 MW of battery storage through 2034;
- Capacity upgrades at several of FPL's existing CC units through 2028;
- The retirement of Gulf Coast Clean Energy Center Units 4 and 5 at the end of 2029; and
- The addition of a 2x0 CT of approximately 475 MW in 2032.

With the exception of certain resource additions and retirements listed above in the earlier years of the 2025-2034 time period addressed in this 2025 Site Plan, FPL notes that final decisions on other resource options shown in this Site Plan are not needed at this time, nor have they been made. This is particularly relevant to resource additions shown for years increasingly further out in the ten-year reporting period. Consequently, those resource additions are more prone to future change.

III.C Discussion of the Resource Plan and Issues Impacting Resource Planning Work

In considering the resource plans presented in this Site Plan, it is useful to note that there are at least ten significant factors that either influenced the current resource plan or which may result in future changes. These factors are discussed below (in no particular order).

1. **Impacts of the Tax Credits for Batteries and Solar:**
   FPL's resource planning work continues to factor in tax credits for new utility-owned batteries, solar, and hydrogen. For new utility owned standalone batteries, the 30% Investment Tax Credit (ITC) effectively lowers the capital cost for a new battery, with the potential of an additional 10% if the battery is located in a specific area. For new utility-owned solar, a utility can elect a Production Tax Credit (PTC) for new solar that is based on the amount of energy (MWh) the new solar facility generates each year for the first ten years of operation. For future

resource additions, the PTC starts in 2024 at $30 for each MWh generated.[6] The $30 per MWh credit amount for a new solar facility that comes in-service increases with inflation each year. FPL's resource plan presented in this Site Plan accounts for the effects of these tax credits.

2. **The critical need to maintain a balance between load and generating capacity in specific regions of FPL's service area, such as in Northwest Florida and Southeastern Florida (Miami-Dade and Broward counties):**

   This balance has both reliability and economic implications for FPL's system and customers, and it is a key reason that FPL has expanded generation and transmission in specific areas in the past. The battery storage units that FPL is adding throughout the ten-year period will aid in addressing these balance concerns.

3. **The desire to maintain/enhance fuel diversity in the FPL system while considering system economics and reliability:**

   In 2024, FPL used natural gas to generate approximately 72% of the total electricity it delivered to its customers. By 2034, due largely to significant solar additions, the percentage of electricity generated by natural gas for FPL's system is projected to decrease to approximately 46% based on the resource plan presented in this Site Plan. Due to this reliance on natural gas, opportunities to economically maintain and enhance fuel diversity are continually sought, with due consideration given to system economics. For example, FPL is projecting the addition of significant amounts of cost-effective PV generation throughout the ten-year reporting period of this document. These PV additions enhance fuel diversity while at the same time allowing for the lowest cost generation resource to be constructed and operated. To enhance the reliability of these PV solar additions, FPL is planning to add cost-effective battery storage to ensure adequate generation and reserves at the time of the net system peak (FPL's peak after accounting for solar generation).

   In the past, coal-fired units have been examined as an option to increase system fuel diversity. However, coal units have ceased to be viable generation options for a number of reasons which include: (i) increased economic competitiveness of solar and battery storage, (ii) much lower forecasted costs for natural gas, (iii) increased availability of natural gas, and (iv) environmental regulations regarding coal units. Consequently, FPL does not believe that new advanced technology coal units are viable fuel diversity enhancement options in Florida.

Therefore, FPL has focused on: (i) cost-effectively adding solar energy and battery storage to enhance fuel diversity and independence, (ii) diversifying the sources of natural gas, (iii) diversifying the gas transportation paths used to deliver natural gas to FPL's generating units, (iv) using natural gas more efficiently, and (v) expanding the ability of its units to burn liquid fuel as a backup to natural gas. FPL has also launched a pilot project that tests the concept of using green hydrogen as a substitute for some of the natural gas now being used to fuel one of its existing CC units.

Solar Energy: The resource plan in this 2025 Site Plan projects that FPL will have a total of approximately 24,471 MW of PV generation by the end of 2034. Such a level of PV nameplate capacity would represent about 77% of FPL's current total installed capacity (MW). However, the impact of PV contribution in terms of actual energy produced (MWh) is smaller. Because solar energy can only be generated during daylight hours and is impacted by factors such as clouds and rain, PV has a capacity factor of approximately 23% to 30% in the state of Florida. As a result, FPL's solar additions would be projected to supply approximately 35% of the total energy (MWh) delivered in 2034 (as shown in Schedule 6.2 later in this chapter).[7]

Based on the resource plan presented in this 2025 Site Plan, it is projected that by 2034 approximately 99% of all energy produced on FPL's system will be that of natural gas, nuclear, and solar, with solar alone accounting for approximately 35% of all the energy produced by the system. This percentage of energy that is projected to be delivered by nuclear and solar energy sources is significant for a utility system of FPL's size, especially when considering that the total amount of energy projected to be delivered to customers in 2034 will have also increased by approximately 11%. The projections of energy by fuel/generation type are presented in Schedules 6.1 and 6.2 later in this chapter.

Nuclear Energy: In 2008, the FPSC approved the need to increase capacity at FPL's four existing nuclear units and authorized the company to recover project-related expenditures that were approved as a result of annual nuclear cost recovery filings. FPL successfully completed this nuclear capacity uprate project. Approximately 520 MW of additional nuclear capacity was delivered by the project, which represents an increase of approximately 30% more incremental capacity than was originally forecasted when the project began. Additional uprates followed which resulted in approximately 40 MW more capacity. FPL's customers are currently benefitting from lower fuel costs and reduced system emissions provided by this additional nuclear capacity.

In June 2009, FPL began the process of securing Combined Operating Licenses (COL) from the federal Nuclear Regulatory Commission (NRC) for two future nuclear units, Turkey Point Units 6 & 7, that would be sited at FPL's Turkey Point site (the location of two existing nuclear generating units). In April 2018, FPL received NRC approval for these two COLs, and these licenses currently remain valid.

FPL has paused the decision whether to seek FPSC approval to move forward with construction of Turkey Point Units 6 & 7. FPL intends to incorporate into any decision regarding Turkey Point Units 6 & 7 the experience gained from the construction and operation of Georgia Power's Vogtle nuclear units. As a result, the earliest possible in-service dates for Turkey Point 6 & 7 are beyond the ten-year period addressed in this 2025 Site Plan. This Site Plan continues to present the Turkey Point location as a Preferred Site for nuclear generation as indicated in Chapter IV.

On January 30, 2018, FPL applied to the NRC for Subsequent License Renewal (SLR) for FPL's existing Turkey Point Units 3 & 4. The previous license terms for these two existing nuclear units extended into the years 2032 and 2033, respectively. The SLR requested approval to extend the operating licenses by 20 years to 2052 and 2053, respectively. The NRC granted approval for the SLR in December 2019. On February 24, 2022, the NRC on its own accord reversed its adjudicatory decision interpreting environmental rules related to SLRs. In particular, the NRC concluded that its environmental review of all pending SLR requests under the National Environmental Policy Act was insufficient due to inadequacies of the NRC's Generic Environmental Impact Statement (GEIS) for license renewal, which is applicable to all plants. With this action, the NRC directed its staff to amend the Turkey Point Units 3 & 4 operating licenses by removing the 20-year term of licensed operation added by the SLR, thereby restoring the previous operating license expiration dates of 2032 and 2033 for Turkey Point Units 3 & 4, respectively.

Following this decision, SLR applicants had the option to satisfy the environmental review requirements either by requesting the NRC Staff to proceed with an entirely site-specific EIS or by waiting for the NRC to issue a revised GEIS that would address all SLR applications. In response to the NRC's action, FPL decided to pursue an entirely site-specific EIS for Turkey Point Units 3 & 4. The NRC completed its site-specific review of the application and reissued the 20-year SLR term for Turkey Point Units 3 and 4 on September 17, 2024. An intervenor's request for hearing on the Turkey Point SLR application was denied and a petition for review of that decision remains pending before the Commission. For purposes of this Site Plan filing, FPL's resource planning analyses have assumed the continued operation of Turkey Point Units 3 & 4 through the currently pending new license termination dates of 2052 and 2053 for Turkey Point Units 3 & 4, respectively.

In the 3rd Quarter of 2021, FPL applied to the NRC for an SLR for its existing St. Lucie nuclear Units 1 & 2. If approved by the NRC, the SLRs for St. Lucie Units 1 & 2 will extend the licenses for those facilities for an additional 20 years until 2056 and 2063, respectively. The NRC schedule for the review of the St. Lucie SLR application has been delayed as the NRC worked to revise its generic EIS for license renewal in response to the Turkey Point SLR decision. FPL chose to wait for the completion of the NRC's revised GEIS and have the NRC incorporate that generic analysis into its St. Lucie review. The revised GEIS was published in August 2024. The current expectation is that the St. Lucie review, which incorporates the GEIS, will be completed in 2026. The revised GEIS is currently subject to a challenge in the Court of Appeals for the D.C. Circuit, but the NRC's review of the application remains ongoing. Similar to the assumption for the Turkey Point Units, FPL's resource planning analyses have assumed the continued operation of St. Lucie Units 1 & 2 through the new license termination dates of 2056 and 2063 for St. Lucie Units 1 & 2, respectively.

FPL is also continuing to monitor advanced nuclear power options such as small modular reactors (SMR). FPL is planning to begin the initial stages of Early Site Permitting in 2026-2027 timeframe, available as permitted under NRC rules, for a potential SMR at a site that is adjacent to an existing nuclear power plant. This strategic move is aimed at minimizing risks, allowing emerging technologies to mature, and ensuring that robust regulatory frameworks are well-developed prior to deployment, while remaining cognizant of the current high costs of nuclear and SMR development and taking a stepwise approach. FPL is closely monitoring current initiatives at both the Department of Energy and the NRC. By taking these steps early on, FPL aims to be well-positioned to benefit from potential state and federal incentives for future nuclear deployment. The projected in-service date of an SMR would be outside the ten-year period addressed in this Site Plan.

<u>Natural gas sourcing and delivery:</u> FPL utilizes several natural gas pipelines to serve our existing natural gas units in Florida. These pipelines provide reliable, economic, and diverse natural gas supply to FPL and the State of Florida. In FPL NWFL, FPL's plants are served by Gulf South Pipeline Company, LP (Gulf South) and the Florida Gas Transmission Company, LLC (FGT). In peninsular Florida, FPL delivers gas using the FGT and the Gulfstream Natural

Gas System (Gulfstream) pipelines along with the Sabal Trail Transmission and the Florida Southeast Connection pipelines which were placed in service in 2017.

Using natural gas more efficiently: FPL has sought ways to utilize natural gas more efficiently for years. Since 2008, FPL has modernized several of its existing plants sites from older, less efficient units into highly efficient CC units with much lower heat rates and higher capacities. These modernized units have improved the overall efficiency of FPL's system, allowing for higher output while using lower amounts of natural gas. This improved efficiency is graphically shown in Figure ES-2 in the Executive Summary.

Dual-fuel capability at existing units: Efforts are being made to maintain the ability to utilize ultra-low sulfur distillate (ULSD) oil at existing units that have that capability. Four new CTs were added at the Gulf Clean Energy Center in late 2021; these units have the capability to burn either natural gas or ULSD fuel oil. Having backup fuel capability ensures the ability of these units to provide generation even during potential disruptions of gas supply.

In the future, FPL's resource planning group will continue to identify and evaluate alternatives that may maintain or enhance system fuel diversity.

4. **The need to maintain an appropriate balance of DSM and supply resources from the perspectives of both system reliability and operations:**
   As mentioned earlier in Section III.A, FPL utilizes a 10% GRM to ensure that system reliability is not negatively affected by an overreliance on non-generation resources, particularly at times of extreme load. This GRM reliability criterion was developed as a result of extensive analyses – which have been described in detail in prior FPL Site Plans – of FPL's system from both resource planning and system operations perspectives. The potential for overreliance upon non-generating resources for system reliability remains an important resource planning issue and is one that will continue to be examined in ongoing resource planning work.

5. **The significant impact of federal and state energy efficiency codes and standards:**
   As discussed in Chapter II, the load forecasts for FPL include projected impacts from federal and state energy efficiency codes and standards. The magnitude of energy efficiency that is currently projected to be delivered to customers of the single, integrated system through these codes and standards is significant.

These energy efficiency codes and standards are projected to have significant incremental impacts by reducing forecasted Summer and Winter peak loads, and by reducing annual net energy for load (NEL), in FPL's system. From the end of 2024 through the year 2034, these energy efficiency codes and standards are projected to reduce Summer peak load by approximately 2,000 MW, reduce Winter peak load by approximately 520 MW, and reduce annual energy usage by approximately 2,460 GWh.

In addition to lowering the load forecast from what it otherwise would have been, and thus serving to lower projected load and resource needs, this projected energy efficiency from the codes and standards also affects resource planning in another way: it lowers the potential market for utility DSM programs to cost-effectively deliver energy efficiency.

6. The fuel cost and efficiency of FPL's fossil-fueled generation fleet and the avoidance of fuel costs through increased solar generation:

There are two main factors that drive utility system costs for FPL's fossil-fueled generation fleet: (i) forecasted natural gas costs, and (ii) the efficiency with which generating units convert fuel into electricity. Forecasted natural gas costs have recently been one of the lowest cost options for fuel, leading to low overall system fuel costs for FPL's customers when compared to other fuels like oil or coal. In addition to these natural gas costs, FPL customers also experience lower rates resulting from two other characteristics of FPL's system: 1) the amount of solar generation on FPL's system and 2) the efficiency of FPL's fossil-fueled generating units.

In 2024, FPL projects that its customers saved approximately $218 million in system fuel costs from having solar generation on its system. Since 2009 (when FPL began adding large scale universal solar facilities to its generation mix), FPL has avoided over $1.1 billion of fuel costs because of its solar generation.

In regard to the fuel efficiency of FPL's fossil-fueled generating units, the amount of natural gas (BTU) needed to produce a kWh of electricity has declined from approximately 9,621 in 2001 to approximately 7,095 in 2024. This improvement of approximately 27% in fuel efficiency is truly significant, especially when considering the 20,000 MW-plus magnitude of gas-fueled generation on FPL's system. This significant improvement in FPL's fuel efficiency has resulted in FPL's customers saving $650 million in fuel costs in 2024, and an estimated cumulative savings for FPL's customers of approximately $15.3 billion from 2001 through 2024.

7. Projected changes in CO_2 regulation and associated compliance costs:

Since 2007, FPL has evaluated potential carbon dioxide (CO_2) regulation and/or legislation and has utilized projected compliance costs for CO_2 emissions prepared by an independent consultant, ICF, in its resource planning work. FPL continues to utilize ICF's forecast of projected CO_2 compliance costs in its resource planning process. The projected compliance costs in the current plan are the same as those used in the 2024 Ten Year Site Plan.

8. Projected increases in electric vehicle (EV) adoption:

FPL's current load forecast continues to project increasing levels of EV adoption throughout the ten-year period. These projected impacts of EVs on annual energy usage and peak loads are discussed in this document in Chapter II. Both the higher MWh and peak hour MW impacts will have resource planning implications.

9. Enhancing system reliability during extreme weather events:

Over the past several years, extreme weather events have caused significant outages and disruptions to electric grids across the country. These events include widespread hot weather in California in the summer of 2020, historic cold weather in February 2021 in Texas, and extreme cold conditions throughout the Mid-Atlantic and Southeast around Christmas of 2022. FPL's Northwest FL area has continually set records in winter peak demand, including its latest record peak early in 2025 when widespread snowfall occurred throughout northern Florida. In addition to these events, FPL's service area regularly experiences periods of hotter than average weather throughout the year and hurricanes that can potentially affect the output of its generation fleet. While FPL does not plan its system around extreme events, it continues to believe it is prudent to consider and prepare for the possibility of extreme weather events and the ability to reliably serve customers under those circumstances. To that end, FPL has reviewed the lessons learned from the outages and service disruptions experienced in other jurisdictions and enhanced its own system to ensure it is adequately prepared. This includes winterizing FPL's nuclear and fossil-fueled generation units, enhancing cooperation and preparation between FPL and suppliers of natural gas and fuel oil, and keeping generation units as "extreme winter only" units that will provide the lowest cost backup capacity in the event of extreme winter weather in FPL's service area. The battery storage units that FPL is adding throughout the ten-year period will also provide additional reliable capacity during extreme weather events.

FPL will continue to work with regulatory authorities, such as the Florida PSC, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability

Corporation (NERC), to follow their guidance regarding proper planning procedures for extreme weather events.

10. **Ensuring resource adequacy and system reliability throughout the entire year:** FPL's planning processes center around ensuring the reliability of its bulk electric system. For over the past two decades, the metric that drove most of FPL's reliability needs was its minimum 20% standard reserve margin, calculated at the time of summer and winter peak load. However, FPL's evolving system requires more in-depth reliability metrics to fully analyze resource adequacy across every hour of the year and through various potential scenarios, including variations in load, generating outages, and solar performance. Therefore, FPL has expanded use of its LOLP metric to include stochastic modeling that fully encompasses all of these scenarios, leading to a more robust evaluation of the reliability and resource adequacy of FPL's system. FPL's planned resources in this Site Plan address these resource adequacy concerns.

III.D Demand-Side Management (DSM)

FPL has sought and implemented cost-effective DSM programs since 1978. As such, cost-effective DSM has been a key focus of FPL's resource planning work for more than 40 years. During that time, FPL's DSM programs have included many energy efficiency and load management programs and initiatives.

There are several important factors affecting the feasibility and cost-effectiveness of utility DSM programs. The first factor is the growing impact of federal and state energy efficiency codes and standards. As discussed first in Chapters I and II, and earlier in Section III.C above, the projected incremental impacts of these energy efficiency codes and standards during the 2025-2034 time period has significantly lowered FPL's projected load and resource needs. In addition, these energy efficiency codes and standards significantly reduce the potential for cost-effective utility DSM programs.

Another factor placing downward pressure on the cost-effectiveness of utility DSM on the FPL system is the steadily increasing efficiency with which FPL generates electricity. FPL's generating system has steadily become more efficient in its ability to generate electricity using less fossil fuel. For example, the FPL system is projected to use 27% less fossil fuel to generate a MWh in 2025 than it did in 2001. Again, this is very good for FPL's customers because it helps to significantly lower fuel costs and electric rates. However, the improvements in generating system efficiency affect DSM cost-effectiveness by lowering the system fuel costs of energy delivered to FPL's customers. Therefore, the improvements in generating system efficiency reduce the potential fuel savings benefits from the kWh reduction impacts of DSM, thus lowering potential DSM benefits and DSM cost-effectiveness. As FPL adds more and more solar to its system, the overall efficiency of its system will continue to improve. Although the efficiency of FPL's system reduces possible benefits from DSM, FPL will continue to look for innovations and opportunities to cost-effectively empower customers and add system benefits through its DSM programs in the future.

In 2024, new DSM goals for the period 2025-2034 were approved in Docket No. 20240012-EG. FPL filed a DSM Plan to achieve these goals in March 2025. The DSM impacts contained in this Site Plan reflect the demand and energy impacts associated with the currently approved goals and proposed programs.

DSM Programs and Research & Development Efforts in FPL's 2025 DSM Plan

1. **Residential Home Energy Survey (HES)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The HES is also used to identify potential candidates for other FPL DSM programs.

2. **Residential Load Management (On Call)**

This program allows FPL to turn off certain customer-selected appliances using FPL-installed equipment during periods of extreme demand, capacity shortages, system emergencies, or for system frequency regulation. This program also includes a new HVAC on-bill option pilot.

3. **Residential HVAC**

This program encourages customers to install high-efficiency central air-conditioning systems.

4. **Residential Ceiling Insulation**

This program encourages customers to improve their home's thermal efficiency.

5. **Residential New Construction (BuildSmart®)**

This program encourages builders and developers to design and construct new homes to achieve BuildSmart® certification and move towards ENERGY STAR® qualifications.

6. **Residential Low Income**

This program assists low-income customers through FPL-conducted Energy Retrofits and state Weatherization Assistance Provider (WAP) agencies.

7. **Residential Low Income Renter Pilot**

This program encourages the adoption of high efficiency HVAC equipment in low-income rental properties.

8. **Business Energy Evaluation (BEE)**

This program educates customers on energy efficiency and encourages implementation of recommended practices and measures, even if these are not included in FPL's DSM programs. The BEE is also used to identify potential candidates for other FPL DSM programs.

9. **Commercial/Industrial Demand Reduction (CDR)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies.

10. **Commercial/Industrial Load Control (CILC)**

This program allows FPL to control customer loads of 200 kW or greater during periods of extreme demand, capacity shortages, or system emergencies. It was closed to new participants as of December 31, 2000.

11. **Commercial Curtailable Load Program**

This program allows FPL to request curtailment of customer loads with a minimum commitment of 4,000 kW of Non-Firm Demand during periods of capacity shortages or system emergencies. The program was closed to new participants December 31, 2021.

12. **Business On-Call**

This program allows FPL to turn off customers' direct expansion central electric air conditioning units using FPL-installed equipment during periods of extreme demand, capacity shortages, or system emergencies.

13. **Business Heating, Ventilating and Air Conditioning (HVAC)**

This program encourages customers to install high-efficiency HVAC systems.

14. **Business Lighting**

This program encourages customers to install high-efficiency lighting systems.

15. **Business Custom Incentive (BCI)**

This program encourages customers to install unique high-efficiency technologies not covered by other FPL DSM programs.

16. **Conservation Research & Development (CRD) Project**

This project consists of industry research and studies designed to: identify new energy-efficient technologies; evaluate and quantify their impacts on energy, demand and customers; and where appropriate and cost-effective, incorporate an emerging technology into a DSM program.

III.E Transmission Plan

The transmission plan will allow for the reliable delivery of the required capacity and energy to FPL's retail and wholesale customers. The following table presents FPL's proposed future additions of 230 kV and above bulk transmission lines that must be certified under the Transmission Line Siting Act (TLSA). There is one such line in the FPL system for this ten-year reporting period.

Table III.E.1: List of Proposed Power Lines

(1) Line Ownership	(2) Terminals (To)	(3) Terminals (From)	(4) Line Length CKT. Miles	(5) Commercial In-Service Date (Mo/Yr)	(6) Nominal Voltage (KV)	(7) Capacity (MVA)
FPL	Sweatt 1/	Whidden	79	June/2026	230	1195

1/ Need Determination for the Whidden to Sweatt project was approved on May 17, 2022, and Conditions of Certification were received in September 2022. The project is scheduled to be completed by June 2026.

There will also be transmission facilities needed to connect several projected generation capacity additions to the FPL transmission system. These transmission facilities are described on the following pages. Sites for longer term additions, such as projected PV and BESS additions for 2027 and beyond, have not yet been definitively determined so no transmission analyses for these additions have been performed.

III.E.1 Transmission Facilities for the Canoe Battery Energy Storage System Center in Okaloosa County

The work required to connect the approximate 74.5 MW (nameplate, AC) Canoe Battery Energy Storage System Center in Okaloosa County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Mink Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.2 Transmission Facilities for the Blackwater Battery Energy Storage System Center in Santa Rosa County

The work required to connect the approximate 74.5 MW (nameplate, AC) Blackwater Battery Energy Storage System Center in Santa Rosa County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Rooster Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.3 Transmission Facilities for the Chipola River Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Chipola River Battery Energy Storage System Center in Calhoun County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Melvin Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.4 Transmission Facilities for the Fourmile Creek Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Fourmile Creek Battery Energy Storage System Center in Calhoun County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Quincy Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.5 Transmission Facilities for the Tenmile Creek Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Tenmile Creek Battery Energy Storage System Center in Calhoun County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Tenmile Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this

III.E.6 Transmission Facilities for the Shirer Branch Battery Energy Storage System Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Shirer Branch Battery Energy Storage System Center in Calhoun County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Mayo Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.7 Transmission Facilities for the Kayak Battery Energy Storage System Center in Okaloosa County

The work required to connect the approximate 74.5 MW (nameplate, AC) Kayak Battery Energy Storage System Center in Okaloosa County in the 4th Quarter of 2025 is projected to be:

I. Substation:

1. Extend the existing 34.5 kV bus at Kayak Substation to connect the BESS.
2. Add relays and other protective equipment.
3. Breaker replacements: None

II. Transmission:

1. No additional transmission work is required.
2. No upgrades are expected to be necessary at this time.

III.E.8 Transmission Facilities for the Flatford Solar Energy Center in Manatee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Flatford Solar Energy Center in Manatee County in the 1st Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Flatford) on the project site, adjacent to the Gridiron - Lemur 230 kV line corridor.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Flatford substation.
3. Construct 34.5 kV bus to connect the PV array to Flatford 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Gridiron - Lemur 230 kV line into Flatford substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.9 Transmission Facilities for the Mare Branch Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Mare Branch Solar Energy Center in DeSoto County in the 1st Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new 230 kV substation (Stallion) on the project site.
2. Add one 230 kV line switch at Whidden for string bus to Stallion substation (approximately 7.0 miles).
3. Add one 230kV breaker at Stallion substation.
4. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
5. Construct 34.5 kV bus to connect the PV array to Stallion 230 kV substation.
6. Add relays and other protective equipment.
7. Breaker replacements: None

II. Transmission:

1. Construct approximately 7.0 miles string bus from Whidden 230 kV to Stallion substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.10 Transmission Facilities for the Price Creek Solar Energy Center in Columbia County

The work required to connect the approximate 74.5 MW (nameplate, AC) Price Creek Solar Energy Center in Columbia County in the 1st Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Madonna) on the project site, adjacent to the Claude - Raven 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Madonna substation.
3. Construct 34.5 kV bus to connect the PV array to Madonna 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent Claude - Raven 230 kV into Madonna substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.11 Transmission Facilities for the Swamp Cabbage Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Swamp Cabbage Solar Energy Center in Hendry County in the 1st Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Swamp) on the project site, approximately 3.15 miles from the Alva - Witt 230 kV line corridor.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Swamp substation.
3. Construct 34.5 kV bus to connect the PV array to Swamp 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Alva - Witt 230 kV line (approximately 3.15 miles) into Swamp substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.12 Transmission Facilities for the Big Brook Solar Energy Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Big Brook Solar Energy Center in Calhoun County in the 1st Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Song) on the project site, adjacent to the Melvin – Tenmile 230 kV line corridor.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Song substation.
3. Construct 34.5 kV bus to connect the PV array to Song 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the Melvin - Tenmile 230 kV line into Song substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.13 Transmission Facilities for the Mallard Solar Energy Center in Brevard County

The work required to connect the approximate 74.5 MW (nameplate, AC) Mallard Solar Energy Center in Brevard County in the 1st Quarter of 2026 is projected to be:

I. **Substation:**

1. Construct a new 230 kV substation (Goodwin) on the project site.
2. Add one 230 kV line switch at Crayfish for string bus to Goodwin substation (approximately 0.7 miles).
3. Add one 230kV breaker at Goodwin substation
4. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
5. Construct 34.5 kV bus to connect the PV array to Goodwin 230 kV substation.
6. Add relays and other protective equipment.
7. Breaker replacements: None

II. **Transmission:**

1. Construct approximately 0.7 miles string bus from Crayfish 230 kV to Goodwin substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.14 Transmission Facilities for the Boardwalk Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Boardwalk Solar Energy Center in Collier County in the 1st Quarter of 2026 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Puma substation to a new substation (Boardwalk) and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None.

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.15 Transmission Facilities for the Goldenrod Solar Energy Center in Collier County

The work required to connect the approximate 74.5 MW (nameplate, AC) Goldenrod Solar Energy Center in Collier County in the 1st Quarter of 2026 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Boardwalk substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Boardwalk 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.16 Transmission Facilities for the North Orange Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) North Orange Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Apricot) on the project site, adjacent to the future Sunbreak – future Muscadine 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Apricot substation.
3. Construct 34.5 kV bus to connect the PV array to Apricot 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent Sunbreak - Muscadine 230 kV into Apricot substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.17 Transmission Facilities for the Sea Grape Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sea Grape Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Muscadine) on the project site, adjacent to the future Sunbreak - Morrow 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Muscadine substation.
3. Construct 34.5 kV bus to connect the PV array to Muscadine 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent Sunbreak - Morrow 230 kV into Muscadine substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.18 Transmission Facilities for the Clover Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Clover Solar Energy Center in St. Lucie County in the 2nd Quarter of 2026 is projected to be:

I. **Substation:**

1. Construct a new 230 kV substation (Clover) on the project site.
2. Add one 230 kV line switch at future Sunbreak for string bus to Clover substation (approximately 0.1 miles).
3. Add one 230kV breaker at Clover substation.
4. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array.
5. Construct 34.5 kV bus to connect the PV array to Clover 230 kV substation.
6. Add relays and other protective equipment.
7. Breaker replacements: None

II. **Transmission:**

1. Construct approximately 0.1 miles string bus from Sunbreak 230 kV to Clover substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.19 Transmission Facilities for the Sand Pine Solar Energy Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Sand Pine Solar Energy Center in Calhoun County in the 2nd Quarter of 2026 is projected to be:

I. Substation:

1. Extend 230 kV bus at Quincy substation to a new substation (Chinkapin) and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Chinkapin 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None.

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.20 Transmission Facilities for the Hendry Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Hendry Solar Energy Center in Hendry County in the 1st Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 500 kV bus at Ghost substation and interconnect the 500/34.5kV transformer through a 500kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Ghost 500 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.21 Transmission Facilities for the Tangelo Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Tangelo Solar Energy Center in Okeechobee County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Seville substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Seville 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.22 Transmission Facilities for the Wood Stork Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Wood Stork Solar Energy Center in St. Lucie County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Glint substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Glint 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.23 Transmission Facilities for the Indrio Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Indrio Solar Energy Center in St. Lucie County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Construct a new single bus, two (2) breaker 230 kV substation (Estuary) on the project site, adjacent to the new Sunbreak - Heritage 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Estuary substation.
3. Construct 34.5 kV bus to connect the PV array to Estuary 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Sunbreak - Heritage 230 kV into Estuary substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.24 Transmission Facilities for the Middle Lake Solar Energy Center in Madison County

The work required to connect the approximate 74.5 MW (nameplate, AC) Middle Lake Solar Energy Center in Madison County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 161 kV bus at Bandit substation and interconnect the 161/34.5kV transformer through a 161kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Bandit 161 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.25 Transmission Facilities for the Ambersweet Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Ambersweet Solar Energy Center in Indian River County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Construct a new single bus, three (3) breaker 230 kV substation (Ambersweet) on the project site, adjacent to the new Sunbreak - Kiran 230 kV line.
2. Add one 230/34.5 kV main step-up transformer (85 MVA) with a 230 kV breaker to connect PV inverter array at Ambersweet substation.
3. Construct 34.5 kV bus to connect the PV array to Ambersweet 230 kV substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. Transmission:

1. Loop the adjacent new Sunbreak - Kiran 230 kV into Ambersweet substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.26 Transmission Facilities for the County Line Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) County Line Solar Energy Center in DeSoto County in the 2nd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Notts substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Notts 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.27 Transmission Facilities for the Saddle Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Saddle Solar Energy Center in DeSoto County in the 2nd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Ponna substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Ponna 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.28 Transmission Facilities for the Cocoplum Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) Cocoplum Solar Energy Center in Hendry County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Witt to a new (Mulberry) substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Mulberry 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.29 Transmission Facilities for the Catfish Solar Energy Center in Okeechobee County

The work required to connect the approximate 74.5 MW (nameplate, AC) Catfish Solar Energy Center in Okeechobee County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Pyrite substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Pyrite 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.30 Transmission Facilities for the Hardwood Hammock Solar Energy Center in Walton County

The work required to connect the approximate 74.5 MW (nameplate, AC) Hardwood Hammock Solar Energy Center in Walton County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Quail substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Quail 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.31 Transmission Facilities for the Maple Trail Solar Energy Center in Baker County

The work required to connect the approximate 74.5 MW (nameplate, AC) Maple Trail Solar Energy Center in Baker County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Deodar substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Deodar 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.32 Transmission Facilities for the Pinecone Solar Energy Center in Calhoun County

The work required to connect the approximate 74.5 MW (nameplate, AC) Pinecone Solar Energy Center in Calhoun County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Chinkapin substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Chinkapin 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.33 Transmission Facilities for the Joshua Creek Solar Energy Center in DeSoto County

The work required to connect the approximate 74.5 MW (nameplate, AC) Joshua Creek Solar Energy Center in DeSoto County in the 3rd Quarter of 2027 is projected to be:

I. Substation:

1. Extend 230 kV bus at Stallion substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Stallion 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.34 Transmission Facilities for the Spanish Moss Solar Energy Center in St. Lucie County

The work required to connect the approximate 74.5 MW (nameplate, AC) Spanish Moss Solar Energy Center in St. Lucie County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Apricot substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
3. Construct 34.5 kV bus to connect the PV array to Apricot 230 kV Substation.
4. Add relays and other protective equipment.
5. Breaker replacements: None

II. **Transmission:**

1. No additional upgrades are expected to be necessary at this time.

III.E.35 Transmission Facilities for the Vernia Solar Energy Center in Indian River County

The work required to connect the approximate 74.5 MW (nameplate, AC) Vernia Solar Energy Center in Indian River County in the 3rd Quarter of 2027 is projected to be:

I. **Substation:**

1. Extend 230 kV bus at Ambersweet substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Ambersweet 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. **Transmission:**

I. No additional upgrades are expected to be necessary at this time.

III.E.36 Transmission Facilities for the LaBelle Solar Energy Center in Hendry County

The work required to connect the approximate 74.5 MW (nameplate, AC) LaBelle Solar Energy Center in Hendry County in the 1st Quarter of 2028 is projected to be:

I. Substation:

1. Extend 230 kV bus at Swamp substation and interconnect the 230/34.5kV transformer through a 230kV breaker.
2. Construct 34.5 kV bus to connect the PV array to Swamp 230 kV Substation.
3. Add relays and other protective equipment.
4. Breaker replacements: None

II. Transmission:

1. No additional upgrades are expected to be necessary at this time.

III.E.37 Transmission Facilities for the Lansing Smith Battery Energy Storage Center in Bay County

The work required to connect the approximate two 200 MW (nameplate, AC) each Lansing Smith Battery Energy Center in Bay County in the 1st Quarter of 2026 is projected to be:

I. **Substation:**

1. Construct a new 230 kV substation (Parakeet) on the project site.
2. Add one 230 kV line switch at Lansing Smith for string bus to Parakeet substation (approximately 0.26 miles).
3. Add two 230/34.5 kV main step-up transformers (225 MVA) with a 230 kV breaker each to connect BESS.
4. Construct 34.5 kV bus to connect the BESS to Parakeet 230 kV substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. **Transmission:**

1. Construct approximately 0.26 miles string bus from Lansing Smith 230 kV to Parakeet substation.
2. No additional upgrades are expected to be necessary at this time.

III.E.38 Transmission Facilities for the Putnam Battery Energy Storage Center in Putnam County

The work required to connect the approximate 200 MW (nameplate, AC) Putnam Battery Energy Center in Putnam County in the 1st Quarter of 2027 is projected to be:

I. Substation:

1. Construct a new 115 kV substation (Putnam BESS U1) on the project site.
2. Add one 115 kV line switch at Putnam switchyard for string bus to Putnam BESS U1 substation (approximately 0.3 miles).
3. Add one 115/34.5 kV main step-up transformers (85 MVA) with a 115 kV breaker to connect the BESS.
4. Construct 34.5 kV bus to connect the BESS to Putnam BESS U1 115 kV substation.
5. Add relays and other protective equipment.
6. Breaker replacements: None

II. Transmission:

1. Construct approximately 0.3 miles string bus from Putnam switchyard 115 kV to Putnam BESS U1 substation.
2. No additional upgrades are expected to be necessary at this time.

III.F. Renewable Resources and Storage Technology

FPL's Renewable Energy Efforts Through 2024:

FPL has been the leading Florida utility in examining ways to effectively utilize renewable energy technologies to serve its customers. Since 1976, FPL has been an industry leader in renewable energy research and development and in facilitating the implementation of various renewable energy technologies. FPL's (including FPL NWFL) renewable energy efforts through 2024 are briefly discussed below in five categories of solar/renewable activities. Plans for new renewable energy facilities from 2025-2034 are then discussed in a separate section.

1) **Early Research & Development Efforts:**
In the late 1970s, FPL assisted the Florida Solar Energy Center (FSEC) in demonstrating the first residential PV system east of the Mississippi River. This PV installation at FSEC's Brevard County location was in operation for more than 15 years and provided valuable information about PV performance capabilities in Florida on both a daily and annual basis. In 1984, FPL installed a second PV system at its Flagami substation in Miami. This 10-kilowatt (kW) system operated for several years before it was removed to make room for substation expansion. In addition, FPL maintained a thin-film PV test facility at the FPL Martin Plant Site for several years to test new thin-film PV technologies.

2) **Demand-Side & Customer Efforts:**
In terms of utilizing renewable energy sources to meet its customers' needs, FPL initiated the first utility-sponsored conservation program in Florida designed to facilitate the implementation of solar technologies by its customers. FPL's Conservation Water Heating Program, first implemented in 1982, offered incentive payments to customers who chose solar water heaters. Before the program ended (because it was no longer cost-effective), FPL paid incentives to approximately 48,000 customers who installed solar water heaters.

In the mid-1980s, FPL introduced another renewable energy program, FPL's Passive Home Program. This program was created to broadly disseminate information about passive solar building design techniques that are most applicable in Florida's climate. As part of this program, three Florida architectural firms created complete construction blueprints for six passive home designs with the assistance of the FSEC and FPL. These designs and blueprints were available to customers at a low cost. During its existence, the program received a U.S.

Department of Energy award for innovation and led to a revision of the Florida Model Energy Building Code which was the incorporation of one of the most significant passive design techniques highlighted in the program: radiant barrier insulation.

FPL has continued to analyze and promote PV utilization. These efforts have included PV research, such as the 1991 research project to evaluate the feasibility of using small PV systems to directly power residential swimming pool pumps. FPL's PV efforts also included educational efforts, such as FPL's Next Generation Solar Station Program. This initiative delivered teacher training and curriculum that was tied to the Sunshine Teacher Standards in Florida. The program provided teacher grants to promote and fund projects in the classrooms.

Gulf Power (Gulf) offered customers the opportunity to contribute to the development of solar PV beginning with the Solar for Schools program in its 1995 DSM Plan. This voluntary program ultimately developed multiple PV installations in schools across Northwest Florida and was used primarily for educational purposes. In 1999, Gulf offered customers an additional opportunity through an optional rate rider. The PV Rate Rider program was intended to give customers an opportunity to contribute towards the construction of a solar PV facility along with other customers across the Southern Company territory.

In 2008, Gulf received FPSC approval to offer an experimental solar water heating program. This program was intended to help customers overcome the high initial cost of adopting solar thermal water heating technology. The program spanned three years and was absorbed into a larger portfolio of renewable program offerings in Gulf's 2010 DSM Plan.

In 2009, as part of its DSM Goals decision, the FPSC imposed a requirement for Florida's investor-owned utilities to spend up to a certain capped amount annually to facilitate demand-side solar water heater and PV applications. The annual spending caps for these applications over the five-year period was approximately $15.5 million per year for FPL and approximately $576,000 per year for Gulf. In response to this direction, FPL received approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of three PV-based programs and three solar water heating-based programs, plus a Renewable Research and Demonstration project. Gulf received similar approval from the FPSC in 2011 to initiate a solar pilot portfolio consisting of two PV-based programs and two solar water heating-based programs. Analyses of the results by both FPL and Gulf from these pilot programs since their inception consistently showed that none of these pilot programs were cost-effective for customers using any of the three cost-effectiveness screening tests used by the State of Florida. As a result, consistent with the

FPSC's December 2014 DSM Goals Order No. PSC-14-0696-FOF-EU, these pilot programs expired on December 31, 2015.

Gulf conducted market research in 2015 indicating customer interest in a renewable energy alternative to private rooftop PV. After further research into innovative offerings across the industry, Gulf developed a subscription-based program model commonly known as community solar. Gulf received FPSC approval in 2016 for a Community Solar program intended to facilitate construction of a 1 MW facility in Northwest Florida once adequate subscriptions were secured. However, customer interest was not adequate enough to justify construction of the project.

In addition, FPL assists customers interested in installing PV equipment at their facilities. Consistent with Rule 25-6.065, F.A.C., Interconnection and Net Metering of Customer-Owned Renewable Generation, FPL works with customers to interconnect these customer-owned PV systems. Through December 2024, approximately 113,097 customer systems (predominantly residential) have been interconnected with FPL (including FPL NWFL). These values represent approximately 2% of FPL's total number of customer accounts.

3) Supply Side Efforts – Power Purchases:

FPL has facilitated several renewable energy projects (facilities which burn bagasse, waste wood, municipal waste, etc.) through PPAs. FPL purchases firm capacity and energy, and/or as-available energy, from these types of facilities. For example, FPL has a contract to receive firm capacity from the Solid Waste Authority of Palm Beach (SWA) through April 2034.

FPL currently has three PPAs with solar facilities totaling approximately 120 MW of nameplate capacity. In addition, FPL has two PPAs totaling approximately 81 MW based, at least in part, on receiving firm amounts of hourly energy from out-of-state sources that were originally wind-generated. Tables I.A.3.1, I.A.3.2, and I.A.3.3 in Chapter I provide information regarding both firm and non-firm capacity PPAs from renewable energy facilities in the two areas.

4) Supply Side Efforts – Utility Owned Facilities:

At the time this Site Plan is filed (April 1, 2025), FPL will own 108 universal solar generating facilities. All of these facilities are PV facilities and together they represent approximately 7,932 MW (nameplate) of generation for FPL. Each of these solar facilities is listed below in Table III.F.1.

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2025

	Solar Energy Center	County	Nameplate MW	Type	COD
1	DeSoto	DeSoto	25	Tracking	Oct-09
2	Space Coast	Brevard	10	Fixed	Apr-10
3	Manatee	Manatee	74.5	Fixed	Dec-16
4	Citrus	Desoto	74.5	Fixed	Dec-16
5	Babcock Ranch	Charlotte	74.5	Fixed	Dec-16
6	Horizon	Alachua/Putnam	74.5	Fixed	Jan-18
7	Coral Farms	Putnam	74.5	Fixed	Jan-18
8	Wildflower	DeSoto	74.5	Fixed	Jan-18
9	Indian River	Indian River	74.5	Fixed	Jan-18
10	Blue Cypress	Indian River	74.5	Fixed	Mar-18
11	Barefoot Bay	Brevard	74.5	Fixed	Mar-18
12	Hammock	Hendry	74.5	Fixed	Mar-18
13	Loggerhead	St. Lucie	74.5	Fixed	Mar-18
14	Miami-Dade	Miami-Dade	74.5	Fixed	Jan-19
15	Interstate	St. Lucie	74.5	Fixed	Jan-19
16	Sunshine Gateway	Columbia	74.5	Fixed	Jan-19
17	Pioneer Trail	Volusia	74.5	Fixed	Jan-19
18	Sweetbay	Martin	74.5	Fixed	Jan-20
19	Northern Preserve	Baker	74.5	Fixed	Jan-20
20	Cattle Ranch	DeSoto	74.5	Tracking	Jan-20
21	Twin Lakes	Putnam	74.5	Tracking	Jan-20
22	Blue Heron	Hendry	74.5	Fixed	Jan-20
23	Babcock Preserve	Charlotte	74.5	Fixed	Jan-20
24	Hibiscus	Palm Beach	74.5	Fixed	Apr-20
25	Okeechobee	Okeechobee	74.5	Fixed	Apr-20
26	Southfork	Manatee	74.5	Tracking	Apr-20
27	Echo River	Suwannee	74.5	Tracking	Apr-20
28	Blue Indigo	Jackson	74.5	Tracking	Apr-20
29	Lakeside	Okeechobee	74.5	Fixed	Dec-20
30	Trailside	St. Johns	74.5	Tracking	Dec-20
31	Union Springs	Union	74.5	Tracking	Dec-20
32	Egret	Baker	74.5	Tracking	Dec-20
33	Nassau	Nassau	74.5	Tracking	Dec-20
34	Magnolia Springs	Clay	74.5	Tracking	Mar-21
35	Pelican	St. Lucie	74.5	Fixed	Mar-21
36	Palm Bay	Brevard	74.5	Fixed	Mar-21
37	Rodeo	DeSoto	74.5	Tracking	Mar-21
38	Sabal Palm	Palm Beach	74.5	Fixed	Apr-21
39	Willow	Manatee	74.5	Tracking	May-21
40	Discovery	Brevard	74.5	Fixed	May-21
41	Orange Blossom	Indian River	74.5	Fixed	May-21
42	Fort Drum	Okeechobee	74.5	Fixed	Jun-21
43	Blue Springs	Jackson	74.5	Tracking	Dec-21
44	Cotton Creek	Escambia	74.5	Fixed	Dec-21

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2025, Continued

	Solar Energy Center	County	Nameplate MW	Type	COD
45	Ghost Orchid	Hendry	74.5	Fixed	Jan-22
46	Sawgrass	Hendry	74.5	Fixed	Jan-22
47	Sundew	St. Lucie	74.5	Fixed	Jan-22
48	Elder Branch	Manatee	74.5	Tracking	Jan-22
49	Grove	Indian River	74.5	Fixed	Jan-22
50	Immokalee	Collier	74.5	Fixed	Jan-22
51	Everglades	Miami-Dade	74.5	Fixed	Jan-23
52	Pink Trail	St. Lucie	74.5	Fixed	Jan-23
53	Bluefield Preserve	St. Lucie	74.5	Fixed	Jan-23
54	Cavendish	Okeechobee	74.5	Tracking	Jan-23
55	Anhinga	Clay	74.5	Tracking	Jan-23
56	Blackwater River	Santa Rosa	74.5	Fixed	Jan-23
57	Chipola River	Calhoun	74.5	Tracking	Jan-23
58	Flowers Creek	Calhoun	74.5	Tracking	Jan-23
59	First City	Escambia	74.5	Fixed	Jan-23
60	Apalachee	Jackson	74.5	Tracking	Jan-23
61	Wild Azalea	Gadsden	74.5	Tracking	Feb-23
62	Chautauqua	Walton	74.5	Tracking	Feb-23
63	Shirer Branch	Calhoun	74.5	Tracking	Feb-23
64	Saw Palmetto	Bay	74.5	Tracking	Apr-23
65	Cypress Pond	Washington	74.5	Tracking	Apr-23
66	Etonia Creek	Putnam	74.5	Tracking	Apr-23
67	Terrill Creek	Clay	74.5	Tracking	Jan-24
68	Silver Plam	Palm Beach	74.5	Tracking	Jan-24
69	Ibis	Brevard	74.5	Tracking	Jan-24
70	Orchard	Indian River/St. Lucie	74.5	Tracking	Jan-24
71	Beautyberry	Hendry	74.5	Tracking	Jan-24
72	Turnpike	Indian River	74.5	Tracking	Jan-24
73	Monarch	Martin	74.5	Tracking	Jan-24
74	Caloosahatchee	Hendry	74.5	Tracking	Jan-24
75	White Tail	Martin	74.5	Tracking	Jan-24
76	Prairie Creek	DeSoto	74.5	Tracking	Jan-24
77	Pineapple	St. Lucie	74.5	Tracking	Jan-24
78	Canoe	Okaloosa	74.5	Tracking	Jan-24
79	Sambucus	Manatee	74.5	Tracking	Mar-24
80	Sparkleberry	Escambia	74.5	Tracking	Mar-24
81	Three Creeks	Manatee	74.5	Tracking	Mar-24
82	Fourmile Creek	Calhoun	74.5	Tracking	Mar-24
83	Big Juniper Creek	Calhoun	74.5	Tracking	Mar-24
84	Pecan Tree	Walton	74.5	Tracking	Mar-24
85	Wild Quail	Walton	74.5	Tracking	Mar-24
86	Hawthorne Creek	DeSoto	74.5	Tracking	Mar-24
87	Nature Trail	Baker	74.5	Tracking	Mar-24
88	Woodyard	Hendry	74.5	Tracking	Mar-24

Table III.F.1: List of FPL-Owned Solar Facilities Through April 1st, 2025, Continued

	Solar Energy Center	County	Nameplate MW	Type	COD
89	Honeybell	Okeechobee	74.5	Tracking	Nov-24
90	Buttonwood	St. Lucie	74.5	Tracking	Nov-24
91	Mitchell Creek	Escambia	74.5	Tracking	Nov-24
92	Hendry Isles	Hendry	74.5	Tracking	Nov-24
93	Georges Lake	Putnam	74.5	Tracking	Nov-24
94	Cedar Trail	Baker	74.5	Tracking	Nov-24
95	Norton Creek	Madison	74.5	Tracking	Dec-24
96	Kayak	Okaloosa	74.5	Tracking	Dec-24
97	Holowpaw	Palm Beach	74.5	Tracking	Jan-25
98	Speckled Perch	Okeechobee	74.5	Tracking	Jan-25
99	Big Water	Okeechobee	74.5	Tracking	Jan-25
100	Fawn	Martin	74.5	Tracking	Jan-25
101	Hog Bay	DeSoto	74.5	Tracking	Jan-25
102	Green Pasture	Charlotte	74.5	Tracking	Jan-25
103	Thomas Creek	Nassau	74.5	Tracking	Jan-25
104	Redlands	Miami-Dade	74.5	Fixed	Jan-25
105	Fox Trail	Brevard	74.5	Tracking	Jan-25
106	Long Creek	Manatee	74.5	Tracking	Jan-25
107	Swallowtail	Walton	74.5	Tracking	Jan-25
108	Tenmile Creek	Calhoun	74.5	Tracking	Jan-25

5) **Ongoing Research & Development Efforts:**

FPL has a “Living Lab” across several of its office locations and select customer sites to demonstrate FPL’s renewable energy commitment to employees and visitors. Through various Living Lab projects, FPL is able to evaluate multiple solar and storage technologies and applications for the purpose of developing a renewable business model resulting in the most cost-effective and reliable uses for FPL’s customers. FPL currently has approximately 293 kW of PV as part of the Living Lab, including a 157 kW floating solar installation in Miami-Dade County that can enable FPL to compare generation and O&M costs for floating versus ground-mount solar PV. In 2020, FPL expanded the Living Lab to include residential sites around Palm Beach County to test battery storage in a residential setting. The test addresses both potential benefits of having a 5-to-8 kW storage system for home backup power and the ability of FPL to remotely control the storage systems to provide services to the electric grid. In 2021, FPL added solar PV paired with battery storage in a residential setting and 460 kW of linear generators. FPL plans to continue to expand the Living Lab as new technologies come to market.

FPL has also been in discussions with several private companies on multiple emerging technology initiatives, including ocean current, thermal storage, hydrogen, fuel cell technology, and energy storage.

Regarding PV's impact on the FPL system, FPL developed a methodology to determine what firm capacity value at FPL's Summer and Winter peak hours would be appropriate to apply to existing and potential PV facilities. The potential capacity contribution of PV facilities is dependent upon several factors including: site location, technology, design, and the total amount of solar that is operating on FPL's system.

Based on the results of its analyses using that methodology, firm capacity values are assigned to each new solar facility. These firm capacity values are described in terms of the percentage of the facility's nameplate (AC) rating that can be counted on as firm capacity at the Summer and Winter peak load hours. For example, two of FPL's earliest PV facilities, DeSoto and Space Coast, have been assigned firm capacity values of approximately 46% for DeSoto and 32% for Space Coast at FPL's Summer peak hour (that typically occurs in the 4 p.m. to 5 p.m. hour), but contribute firm capacity of only 3% for DeSoto and 1% for Space Coast during FPL's Winter peak hour (that typically occurs in the 7 a.m. to 8 a.m. hour). Similarly, each new solar facility is assigned a specific firm capacity value based on the factors described above. Information on each solar unit's firm capacity is available in the footnotes of Schedule 1 in Chapter I and the entries for new units in Schedule 8 later in this chapter. FPL will continue to evaluate the firm capacity assigned to solar and battery facilities as it adapts more sophisticated resource adequacy methods like stochastic LOLP.

FPL has also conducted research on residential battery systems to evaluate both the potential to shift solar contribution to peak hours and to dispatch storage as a demand-response resource.

Renewable Energy, Battery Storage, and Electric Vehicle Projections for 2025 through 2034:

This section addresses efforts regarding renewable energy in both universal (utility-scale) and distributed solar, as well as FPL's SolarTogether™ program. In addition, efforts regarding battery storage are also addressed. These efforts and plans are summarized below.

1. **Utility-Scale Solar:**

In 2009, FPL constructed 110 MW of solar energy facilities including two PV facilities totaling 35 MW and one 75 MW solar thermal facility. This solar thermal facility location at the Martin plant, was retired in the 1st Quarter of 2023. From 2009 through 2017, the costs of solar equipment, especially PV equipment, declined significantly and universal PV facilities became increasingly competitive economically with more conventional generation options. As a result, FPL added three new PV facilities of approximately 74.5 MW each near the end of 2016.

In the 1st Quarter of 2018, eight additional PV facilities of 74.5 MW each, or 596 MW in total, also went into commercial operation. These eight PV facilities were added under the Solar Base Rate Adjustment (SoBRA) provision of the Commission's order approving the settlement agreement for FPL's base rate case in 2016 (Order No. PSC-16-0560-AS-EI) and comprised two groups of four solar facilities each. In 2019, four more 74.5 MW PV facilities, or approximately 298 MW, were added as SoBRA facilities. An additional four 74.5 MW PV facilities, or approximately 298 MW, were placed into commercial operation in the 2nd Quarter of 2020. This completed the addition of solar under the 2016 SoBRA mechanism.

In the FPL NWFL service area, a total of three new 74.5 MW PV facilities were added. The first was placed into service in April 2020, and two additional sites achieved commercial operation in December of 2021.

As part of FPL's 2021 Rate Case Settlement (Order PSC-2021-0446-S-EI), the FPSC authorized FPL to construct 447 MW of PV solar in 2022 and an additional 745 MW of PV solar in 2023. The six sites totaling 447 MW in the 2022 group achieved commercial operation in January 2022. The ten additional sites comprising the 2023 group achieved commercial operation in January 2023.

Additionally, the Settlement also authorized FPL to construct 894 MW of PV solar in 2024 and 894 MW in 2025, for a total of 1,788 MW of PV, using a SoBRA mechanism identical in concept to the previous SoBRA. Each of these additions must be cost effective and fall below a cost cap of $1,250 kWac. The first 894 MW of PV solar for the 2024 SoBRA achieved commercial operation in January 2023, and the second 894 MW for the 2025 SoBRA achieved commercial operation in January 2025.

The resource plan presented in this Site Plan continues to show significant additions in solar (PV) resources over the ten-year reporting period. Approximately 17,433 MW of additional PV generation is projected to be added in the 2025-2034 time period. The projected total of solar PV for the single integrated utility by the end of 2034 is equal to 24,471 MW.

Ongoing resource planning work will continue to analyze the projected system economics of solar and all other resource options. Information regarding the Preferred and Potential Sites for the projected solar additions, particularly in the near-term, is presented in Chapter IV and in the Appendix.

2. **Distributed PV Pilot Programs:**

FPL began implementation of two distributed PV pilot programs in 2015. The first is a voluntary, community-based, solar partnership pilot to install new solar-powered generating facilities. The program is funded by contributions from customers who volunteer to participate in the pilot and does not rely on subsidies from non-participating customers. The second program has installed approximately 3.4 MW of distributed generation (DG) PV and expired at the end of 2020. The objective of this second program was to collect grid integration data for DG PV and develop operational best practices for addressing potential problems that may be identified. The PV installed under this pilot program will continue to be evaluated for these purposes. A brief description of these pilot programs follows.

a. **Voluntary, Community-Based Solar Partnership Pilot Program:**

The Voluntary Solar Pilot Program, named FPL SolarNow™, provides FPL customers with a flexible opportunity to support solar power in Florida. The FPSC approved FPL's request for this three-year pilot program in Order No. PSC-14-0468-TRF-EI on August 29, 2014. The pilot program's tariff became effective in January 2015. The final program disposition and five-year extension of the pilot was approved on December 1, 2020 by the FPSC in Order No. PSC-2020-0508-TRF-EI, and the program will now sunset on December 31, 2025.

This pilot program provides all customers the opportunity to support bringing solar projects into local communities by funding the construction of solar facilities in local public areas, such as parks, zoos, schools, and museums. Customers can participate in the program through voluntary contributions of $9/month. As of the end of 2024, there were 33,240 participants enrolled in the Voluntary Solar Pilot Program. This program has installed 84 projects located in 35 communities within the FPL service area. These projects represent approximately 2,531 kW-DC of PV generation.

In addition to the SolarNow™ pilot program, FPL has also installed 121.6 kW (DC) of distributed solar generators at eight different locations and 5.4 kW (DC) of non-grid tied solar throughout the FPL NWFL territory.

b. **C&I Solar Partnership Pilot Program:**

This pilot program was conducted in partnership with interested commercial and industrial customers over an approximately five-year period and expired in 2020. Limited investments were made in PV facilities located at customer sites on selected distribution circuits within FPL's service area.

The primary objective was to examine the effect of high localized PV penetration on FPL's distribution system and to determine how best to address any problems that may be identified. FPL installed approximately 3.8 MW of PV facilities on circuits that experience specific loading conditions to better study feeder loading impacts, with approximately 3.4 MW remaining in operation. In addition, FPL evaluated the integration of solar into urban areas to test its impact on the distribution system on feeders that are heavily loaded.

3. **FPL SolarTogether™ Program:**

In March of 2019, FPL filed for FPSC approval of a community solar program under the market name FPL SolarTogether™. This voluntary program offers FPL customers the option to purchase solar output/attributes from cost-effective, large-scale solar energy centers. The proposed program did not require customers who participate to be bound to a long-term contract or subject to upfront enrollment costs or termination penalties. Under this program, participants' monthly electric bills would show both a subscription charge and a subscription credit line item associated with the subscribers' share of the actual solar energy generated. The FPL SolarTogether™ program was designed to leverage the economies of scale of universal solar to deliver long-term savings to both program participants and non-participants.

In March 2020, the FPSC approved the FPL SolarTogether™ program (Order PSC-2020-0084-S-EI). From 2020 through 2024, FPL has installed 3,278 MW of solar under the SolarTogether™ program. Approximately 1,005 MW has been allocated to residential customers, 2,190 MW has been allocated to commercial, industrial, and governmental customers, and 83 MW have been allocated to the low-income portion of SolarTogether™, marketed as FPL SunAssist™.

4. **Solar Power Facilities Pilot Program:**

As part of FPL's 2021 Settlement Agreement, FPL received approval to offer a four-year voluntary pilot program to commercial and industrial customers that may elect to have FPL install and maintain a solar facility on their site for a monthly tariff charge (the "Solar Power Facilities Pilot Program"). The output of this solar facility would be used solely by the participating customer. The fixed term tariff will recover the project capital costs and ongoing operating expenses through a monthly fixed charge from the program participants, such that the general body of customers will not be impacted.

Battery Storage Efforts:

Battery storage technology has continued to advance, and the cost of storage is projected to continue to decline over the long-term, aided, in part, by continued tax credits. As a result, battery storage is an economically competitive firm capacity option for FPL's system. As previously discussed, a 409 MW battery storage facility was added in late 2021 at the existing Manatee plant site. Additional battery storage capacity was added in late 2021 with 30 MW of battery storage added at both the existing Sunshine Gateway Solar Energy Center and at the Echo River Solar Energy Center. An additional total of approximately 7,603 (nameplate) MW of battery storage is also included in the resource plan through 2034. These batteries help to minimize solar curtailment during shoulder load daytime hours and meet load demand in the evenings and in winter mornings. Batteries are also able to ramp up their output much faster than conventional generation, making them effective at meeting load demand as solar generation reduces during evening hours.

In addition, FPL is analyzing the potential of battery storage technology to benefit FPL's customers in other ways. These analyses have been, and are currently, being carried out through implementation of two pilot projects designed to evaluate different potential applications for batteries on FPL's system.

The objectives of the two pilot projects are to identify the most promising applications for batteries on FPL's system and to gain experience with battery installation and operation. This information will position FPL to expeditiously take advantage of battery storage for the benefit of FPL's customers as the economics of the technology continue to improve. For the purpose of discussing these two pilot projects, they will be referred to as the "small scale" and "large scale" storage pilot projects.

1. **Small Scale Storage Pilot Projects:**

In 2016 and early 2017, FPL installed approximately 4 MW of battery storage systems, spread across six sites, with the general objective of demonstrating the operational capabilities of batteries and learning how to integrate them into FPL's system. These small storage projects were designed with a distinct set of high-priority battery storage grid applications in mind. These applications include peak shaving, frequency response, and backup power. In addition, these initial projects were designed to provide FPL with an opportunity to determine how to best integrate storage into FPL's operational software systems and how best to dispatch and/or control the storage systems.

To this end, FPL installed multiple projects that have been in service for more than eight years and have yielded valuable information regarding the applications listed above. These projects and learnings from them include: (i) a 1.5 MW battery in Miami-Dade County using second life automotive batteries for peak shaving and frequency response (found that high in-house integration costs coupled with low remaining capacity in second-life batteries do not support the business case), (ii) a 1.5 MW battery in Monroe County for backup power and voltage support (showcased the complexity of working with customer's equipment), (iii) a relocatable 0.75 MW uninterruptible power supply (UPS) battery at Trividia Health, Inc. in Broward County (provides consistent support to mitigate customer's momentary disruptions and reliability issues but relocation is costly and requires high technical expertise), and (iv) smaller kilowatt-scale systems in several communities for distributed storage reliability (applications successfully provide reliability support for residential customers during grid events but FPL found front-of-the-meter deployment is more expensive than BTM installations). FPL decommissioned the 1.5 MW battery in in Miami-Dade County, the 0.75 MW UPS and the small kilo-watt scale systems in several communities at the end of 2022.

2. **Large Scale (50 MW) Storage Pilot Project:**

The small-scale battery storage pilot projects described above are complemented by up to 50 MW of additional battery projects. These pilot projects were authorized under the Settlement Agreement in FPL's 2016 base rate case. The 50 MW of batteries that have been, and will continue, to be deployed in this larger pilot project have expanded the number of storage applications and configurations that FPL will be able to test and have made the scale of deployment more meaningful given the large size of FPL's system.

The first two storage projects under this pilot, placed in-service in the 1st Quarter of 2018, involve pairing battery storage with existing universal PV facilities. One of the projects is a 4

MW battery sited at FPL's Citrus Solar Energy Center. This project captures clipped (curtailed) solar energy from the solar panels during high solar insolation hours, then releases this energy in other hours. The second project is a 10 MW battery at FPL's Babcock Ranch Solar Energy Center. This project is designed to shift PV output from non-peak times to peak times and to provide "smoothing" of solar output and regulation services. These two projects are designed to enhance the operations of existing solar facilities that were installed in 2016. The data and lessons gathered from these two projects enable more optimized design configurations for solar-paired battery projects as well as improved operational parameters for economic dispatch. In 2021, FPL added an additional 1 MW to the existing Babcock Ranch Battery Storage System to test the design and performance of various battery augmentation solutions to mitigate degradation.

In the 4th Quarter of 2019, a 10 MW battery in Wynwood, a dense urban area close to downtown Miami, went into service. The project is designed to examine the use of batteries to support the distribution system with a focus on addressing grid, system, and customer challenges. Key learnings relate to the challenges of installing a battery in a dense urban area, including the decision to install in a building to allow for increased energy density, and integration into the distribution control system to allow for seamless integration into the Automated Feeder Switching system.

Two additional projects placed in-service in 2020 are designed to enhance reliability for FPL customers and the grid. One is an 11.5 MW battery that will augment the Dania Beach Clean Energy Center Unit 7. This project evaluates using battery storage to black start large generating units. The other is a 3 MW battery alongside an existing solar PV system to create a microgrid. The microgrid will be used for local resiliency and to provide additional grid services, including mitigation of disruptions potentially caused by solar in the distribution system. The projects have thus far yielded valuable learnings about interconnection approach and properly sizing the battery to account for the inrush current needed to energize the load for these applications.

The last three projects explore battery storage opportunities associated with electric vehicles (EVs) and EV infrastructure. The first explores the potential for utilizing EVs as grid resources on FPL's system for the first time ever; the 1.25 MW of Electric-Vehicle-to-Grid (EV2G) batteries using electric school buses will be able to discharge electricity to the grid when needed. The first two buses were delivered in the 3rd Quarter of 2020 and 1st Quarter of 2021; the remaining three buses, delayed due to supply chain constraints, were delivered in 2nd

Quarter of 2024. The second EV plus storage pilot adds 0.35 MW of battery storage to two FPL EVolution® pilot sites in Columbia County and Nassau County (0.7 MW total) to provide grid benefits in the form of peak shaving and a reduction in distribution upgrades. The third and final pilot project, the "FPL EVolution® Hub", has two parts: (i) 7.25 MW of storage paired with 5 MW solar PV to create a renewable microgrid, and (ii) two trailers each fitted with 0.65 MW (total 1.3 MW) of storage and 6 EV (12 total) fast chargers. The microgrid will be used to charge the trailers that will be deployed throughout FPL service area during grid events to increase resiliency for EV charging. The microgrid will also be used to provide electricity to a nearby administrative building, warehouse, and several biodiesel tanks when not being used to charge the battery trailers. The first and third pilot projects have completed construction and are operational as of 2022. The EV + Storage project in Columbia and Nassau counties was placed into service in the 1st Quarter in 2024.

A summary of FPL's battery storage facilities is presented in Table III.F.2 below.

Table III.F.2: List of FPL Battery Storage Facilities

In-Service Date	Location/Projects	Status	Nameplate MW
2016-2017	2016 Pilots	Operational	1.5
2018	Citrus Solar Energy Center	Operational	4
2018	Babcock Ranch Solar Energy Center	Operational	10
2019	Wynwood	Operational	10
2020	Dania Beach Energy Center	Operational	11.5
2020	University Microgrid	Operational	3
2020	EV2G	Operational	1.25
2021	Manatee	Operational	409
2021	Sunshine Gateway	Operational	30
2021	Echo River	Operational	30
2023	EV + Storage	Operational	0.7
2022	FPL EVolution® Hub	Operational	8.55
		Total:	**520**

Electric Vehicle Efforts:

Florida is ranked second in the nation for EV adoption, and more Floridians are buying EVs every year. FPL began implementation of the FPL EVolution® pilot program in 2019 to support the growth of EVs with the goal to install more than 1,000 charging ports. The primary objective of this pilot program for FPL is to gather data and learnings ahead of projected mass EV adoption to ensure future EV investments enhance service and reduce costs. The FPL EVolution® Pilot focuses on three key areas: a) influences of infrastructure build-out on adoption; b) rate structures and demand models; and c) grid impacts of fast-charging. This pilot program is being conducted in partnership with interested host customers over an approximate three-year period. Installations encompass different EV charging technologies and market segments, including level 2 workplace charging at public and/or private workplaces; destination charging at well-attended locations; residential charging at customers' homes; and fast charging in high-traffic areas, along highway corridors and evacuation routes to enable long distance travel. These places include Florida's Turnpike Service Plazas, public parking areas, tourist attractions, hospitals, and large businesses that employ hundreds of Florida residents.

As part of FPL's 2021 Settlement Agreement, FPL received approval to expand the initial FPL EVolution® Pilot and add additional EV programs that were launched in 2022, including: i) public fast charging, ii) new technologies and software, iii) education and outreach, iv) a voluntary residential EV charging services tariff, and v) a voluntary commercial EV charging services tariff.

In addition, pursuant to Order No. 2020-0512-TRF-EI, issued December 21, 2020, FPL has implemented three optional five-year EV public charging pilot tariffs. The first tariff, Utility-Owned Public Charging for Electric Vehicles (Rate Schedule UEV), establishes a rate for FPL to charge drivers directly at certain utility-owned FPL EVolution® fast charging stations. The second set of tariffs, Electric Vehicle Charging Infrastructure Riders to General Service Demand and General Service Large Demand (Rate Schedules GSD-1EV and GSLD-1EV), limit the demand cost associated with general service demand rates billed to third-party public charging stations operating in FPL's service area. The tariffs took effect in January 2021 and will last for a period of five years.

As of December 31, 2024, FPL EVolution® Public has installed 910 Level 2 charging ports and 321 fast charging ports. There are 76 FPL EVolution fast charging sites operating under the UEV rate schedule and approximately 200 additional ports expected to be online by the end of 2025. FPL has also added 274 charging ports under the fleet pilot in 2024 and 30 level 2 charging ports under the CEVCS-1 tariff in 2025. Additionally, FPL added 9,007 level 2 chargers for residential customers, allowing managed EV charging during off-peak hours, avoiding additional load during peak. The FPL EVolution® pilot has provided FPL valuable early insights and best practices into EV charging infrastructure deployment in the areas of siting, equipment, installation, and grid reliability.

III.G Fuel Mix and Fuel Price Forecasts

1. FPL Fuel Mix

FPL's fuel mix since the early 1990s has seen a steady increase in the amount of natural gas, which FPL uses to produce electricity due, in part, to the introduction of highly efficient and cost-effective CC generating units and the ready availability of abundant, U.S.-produced natural gas. Since 2001, FPL has focused on modernizing its gas-fired generation fleet by modernizing existing units and adding CC units to its generation mix. These new CC units have dramatically improved the efficiency of FPL's generation system in general and, more specifically, the efficiency with which natural gas is utilized as discussed in the Executive Summary.

In regard to access to alternative fuel availability, the addition of four CTs at the Gulf Clean Energy Center in 2021, capable of burning natural gas or ULSD oil, has also provided additional fuel diversity and reliability.

FPL has also taken measures over the last few years to eliminate the use of coal as a fuel. FPL shuttered Cedar Bay in 2016, St. Johns River Power Park in 2018, the Indiantown Co-Gen coal-fueled unit in late 2020, and the Scherer 4 unit on January 1, 2022. The conversion of the Gulf Clean Energy Center to natural gas in 2020, plus the retirement of FPL's ownership portion of the Daniel Units 1 & 2 in January 2024 demonstrates a continued commitment to eliminate coal from the generation portfolio.

In addition, FPL increased its utilization of nuclear energy through capacity uprates of its four existing nuclear units. With these uprates, more than 500 MW of additional nuclear capacity have been added to the FPL system. As mentioned previously, FPL has obtained the COLs from the NRC for two new nuclear units, Turkey Point Units 6 & 7. FPL has now paused this process to decide when to pursue approval from the FPSC to proceed to construction.

By the end of April 2025, FPL will have approximately 7,932 MW of renewable PV generating capability comprised mainly of 74.5 MW solar facilities at 108 sites. A significant amount of additional solar is projected in the current resource plan as discussed throughout this Site Plan.

These solar additions will increase solar as a percentage of FPL's generation from 9% in 2024 to 35% in 2034.

Ongoing resource planning work will continue to focus on identifying and evaluating alternatives that would most cost-effectively maintain and/or enhance long-term fuel diversity. These fuel-diverse alternatives may include additional solar energy facilities, obtaining additional access to diversified sources of natural gas such as liquefied natural gas (LNG) and natural gas from the Mid-Continent and Marcellus regions, preserving the ability to utilize fuel oil at existing units, and increased utilization of nuclear energy, and the purchase of power from renewable energy facilities (As previously discussed, new, advanced technology coal-fueled generating units are no longer considered as viable options in Florida). The evaluation of the feasibility and cost-effectiveness of these and other possible fuel diversity alternatives will be part of on-going resource planning efforts.

As part of the effort to introduce further fuel diversity and resiliency into FPL's generation system, a green hydrogen electrolysis pilot project has been developed and deployed at FPL's Okeechobee CC unit. This pilot utilizes solar energy to perform electrolysis and generate hydrogen fuel. This hydrogen fuel is then burned in a portion of the combined cycle unit to test the capability of FPL's existing units to burn hydrogen instead of natural gas. This pilot allows FPL to assess how the CTs in a CC unit operate with a hydrogen and natural gas fuel mix, and also provides insight into how a hydrogen fuel production and storage facility can be effectively used on site with combustion turbine units. To provide a source of hydrogen to burn for this pilot, FPL built an approximate 25 MW electrolyzer and a storage facility for the production and on-site storage of hydrogen at Okeechobee. The electrolyzer is interconnected with renewable generation at the Okeechobee site so that electrical energy from a solar facility can be used by the electrolyzer to separate water into hydrogen and oxygen gases. The oxygen is released into the air while the hydrogen is compressed and stored on-site where it can later be used as fuel in the CT units at the Okeechobee site. This pilot project went into service in late 2023.

Current use of various fuels to supply energy to customers, plus projections of this "fuel mix" through 2034 based on the resource plan presented in this document, are presented in Schedules 5, 6.1, and 6.2 that appear later in this chapter.

2. Fossil Fuel Cost Forecasts

FPL's Fuel Cost Forecasts

Fossil fuel price forecasts, and the resulting projected price differentials between fuels, are major drivers used to evaluate alternatives for meeting future resource needs. FPL's forecasts are generally consistent with other published contemporary forecasts. A September 2024 fuel cost forecast was used in the analyses which developed the resource plans presented in this 2025 Site Plan.

Future oil and natural gas prices, and to a lesser extent, coal prices, are inherently uncertain due to a significant number of unpredictable and uncontrollable drivers that influence the short- and long-term price of oil, natural gas, and coal. These drivers include U.S. and worldwide demand, production capacity, economic growth, environmental requirements, and politics.

The inherent uncertainty and unpredictability of these factors today and in the future clearly underscore the need to develop a set of plausible oil, natural gas, and solid fuel (coal) price scenarios that will bound a reasonable set of long-term price outcomes. In this light, Low, Medium, and High price forecasts for fossil fuels were developed in anticipation of the 2025 resource planning work.

FPL's Medium price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's Medium price forecast applies the following methodology:

a. For the then-current plus two years (2024-2026), the methodology used the September 2024 forward curve for New York Harbor 0.5% sulfur heavy oil, WTI Crude Oil, Ultra-Low Sulfur Diesel (ULSD) fuel oil, and Henry Hub natural gas commodity prices (As S&P Global no longer publishes a Long Term forecast for 0.7% Sulfur Heavy Oil, FPL now forecasts a 0.5% Sulfur heavy oil price using a combination of market quotes and 1% Sulfur heavy oil price forecasts);

b. For the next two years (2027 and 2028), FPL used a 50/50 blend of the September 2024 forward curve and the most current projections at the time from S&P Global (formerly called The PIRA Energy Group);

c. For the 2029-2050 period, FPL used the annual projections from S&P Global for oil and natural gas commodity prices;

d. For the period beyond 2050 for oil and natural gas, FPL used the real rate of escalation from the Energy Information Administration (EIA). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's Medium price forecast methodology is also consistent for coal prices. FPL uses a combination of actual coal purchases, current market quotes provided to FPL, Long Term PRB Coal price forecast up to 2050 from S&P Global and rail rate growth from historical data to build a coal price forecast for Plant Scherer.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. FPL's approach has been to then adjust the Medium fuel cost forecast upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

3. Natural Gas Storage

FPL currently has under contract 4.0 billion cubic feet (Bcf) of firm natural gas storage capacity at the Bay Gas storage facility in Alabama. This contract has been extended through March 31, 2029. FPL has predominately utilized natural gas storage to help mitigate gas supply problems caused by severe weather and/or infrastructure problems. To diversify FPL's natural gas storage portfolio, FPL entered into a storage contract with SG Resources Mississippi, L.L.C. (Southern Pines Storage) for 1 Bcf of storage capacity. The current contract with Southern Pines Storage is set to expire March 31, 2030. This storage facility is located in Mississippi and is connected to numerous pipelines including FGT, Southeast Supply Header, and Transco. Effective April 1, 2025, FPL will add an incremental 2 Bcf of storage capacity at Petal Storage located in Mississippi; the contract will extend through March 31, 2028.

FPL's ability to manage the daily "swings" in natural gas demand that can occur on its system due to weather and unit availability changes is challenging, particularly from oversupply situations. Natural gas storage is a valuable tool to help manage the daily balancing of supply and demand. From a balancing perspective, injection and withdrawal rights associated with gas storage have become an increasingly important part of the evaluation of overall gas storage requirements.

As FPL's system grows to meet customer needs, it must maintain adequate gas storage capacity to continue to help mitigate supply and/or infrastructure problems and to provide the ability to manage its supply and demand on a daily basis. The gas storage portfolio is continually evaluated and subscription for additional gas storage capacity is possible if needed to help increase reliability, provide the necessary flexibility to respond to demand changes, and diversify the overall portfolio.

4. **Securing Additional Natural Gas**

Reliance upon natural gas to produce electricity for FPL's customers is projected to continue for a number of years due to FPL's growing load. As discussed above, FPL plans to add significantly more solar PV facilities that utilize no fossil fuel and will reduce FPL's reliance on natural gas throughout the ten-year period of the Site Plan and beyond.

FPL has historically purchased the gas transportation capacity required for new natural gas supply from two existing natural gas pipeline companies: FGT and Gulfstream. In mid-2017, a third new pipeline system, consisting of the Sabal Trail and Florida Southeast Connection pipelines, went into operation. This new pipeline system is now providing fuel for FPL's Riviera, Okeechobee, and Martin plants. The new pipeline system will also allow needed support for gas-fueled FPL generation facilities in several counties.

5. Nuclear Fuel Cost Forecast

This section discusses the various steps needed to fabricate nuclear fuel for delivery to nuclear power plants, the method used to forecast the price for each step, and other comments regarding FPL's nuclear fuel cost forecast.

a) Steps Required for Nuclear Fuel to be delivered to FPL's Plants

Four separate steps are required before nuclear fuel can be used in a commercial nuclear power reactor. These steps are summarized below.

(1) Mining: Uranium is produced in many countries such as Canada, Australia, Kazakhstan, and the United States. During the first step, uranium is mined from the ground using techniques such as open pit mining, underground mining, in-situ leaching operations, or production as a by-product from other mining operations, such as gold, copper, or phosphate rocks. The product from this first step is the raw uranium delivered as an oxide, U_3O_8 (sometimes referred to as yellowcake).

(2) Conversion: During the second step, the U_3O_8 is chemically converted into UF_6 which, when heated, changes into a gaseous state. This second step further removes any chemical impurities and serves as preparation for the third step, which requires uranium to be in a gaseous state.

(3) Enrichment: Natural uranium contains 0.711% of uranium at an atomic mass of 235 (U-235) and 99.289% of uranium at an atomic mass of 238 (U-238). FPL's nuclear reactors use uranium with a higher percentage of up to almost five percent (5%) of U-235 atoms. Because natural uranium does not contain a sufficient amount of U-235, the third step increases the percentage amount of U-235 from 0.711% to a level specified when designing the reactor core (typically in a range from approximately 2.0% to as high as 4.95%). The output of this enrichment process is enriched uranium in the form of UF_6.

(4) Fabrication: During the last step, fuel fabrication, the enriched UF_6 is changed to a UO_2 powder, pressed into pellets, and fed into tubes, which are sealed and bundled together into fuel assemblies. These fuel assemblies are then delivered to the plant site for insertion into a reactor.

Like other utilities, FPL has purchased raw uranium and the other components of the nuclear fuel cycle separately from numerous suppliers from different countries.

b) Price Forecasts for Each Step

(1) Mining: The impact of the earthquake and tsunami that struck the Fukushima nuclear complex in Japan in March 2011 is still being felt in the uranium market because the majority of the Japanese nuclear reactors are still not operating. As a result, current demand has remained declined and several of the production facilities have either closed or announced delays. Factors of importance are:

- Some of the uranium inventory from the U.S. Department of Energy (DOE) is finding its way into the market periodically to fund cleanup of certain DOE facilities.
- Although only two new nuclear units are starting production in the U.S. in the short-term, other countries have announced an increase in construction of new units which may cause uranium prices to trend up in the near future.

Over a ten-year horizon, FPL expects the market to be more consistent with market fundamentals. The supply picture remains stable, with laws enacted in 2020 to resolve the import of Russian-enriched uranium, by allowing continued imports of Russian-enriched uranium to meet about 15-24% of needs from 2025-2040 for currently operating and new units. New and current uranium production facilities are decreasing capacity due to continued low prices and demands. Actual demand tends to grow over time because of the long lead time to build nuclear units. However, FPL cannot discount the possibility of future periodic sharp increases in prices but believes such occurrences will likely be temporary in nature.

(2) Conversion: The conversion market is also in a state of flux due to the Fukushima events. Planned production is currently forecasted to be insufficient to meet a higher demand scenario, but it is projected to be sufficient to meet most reference case scenarios. As with additional raw uranium production, supply will expand beyond the current level if more firm commitments are made. FPL expects long-term price stability for conversion services to support world demand.

(3) Enrichment: Since the Fukushima events in March 2011, the near-term price of enrichment services has declined. However, plans for construction of several new facilities that were expected to come on-line after 2011 have been delayed and/or cancelled. Also, some of the existing high operating cost diffusion plants have shut down. As with supply for the other steps of the nuclear fuel cycle, expansion of future capacity is feasible within the lead time for constructing new nuclear units and any other projected increase in demand. Meanwhile, world supply and demand will continue to be balanced such that FPL expects an adequate supply of enrichment services. The current supply/demand profile will likely result in the price of enrichment services remaining stable for the next few years, then starting to increase.

(4) Fabrication: Because the nuclear fuel fabrication process is highly regulated by the NRC, not all production facilities can qualify as suppliers to nuclear reactors in the U.S. Although world supply and demand are expected to show significant excess capacity for the foreseeable future, the gap is not as wide for U.S. supply and demand. The supply for the U.S. market is expected to be sufficient to meet U.S. demand for the foreseeable future.

c) Other Comments Regarding FPL's Nuclear Fuel Cost Forecast

FPL's nuclear fuel price forecasts are the result of FPL's analysis based on inputs from various nuclear fuel market expert reports and studies. There is adequate projected supply, including planned and prospective mine expansions, to meet FPL demands, including operation of the two Turkey Point nuclear units, even through the 2052 and 2053 dates that are a part of FPL's SLR requests for these units.

Schedule 5: Actual
Fuel Requirements

	Fuel Requirements	Units	Actual [1/] FPL 2023	Actual [1/] FPL 2024
(1)	Nuclear	Trillion BTU	310	301
(2)	Coal	1,000 TON	474	372
(3)	Residual (FO_6) - Total	1,000 BBL	0	0
(4)	Steam	1,000 BBL	0	0
(5)	Distillate (FO_2) - Total	1,000 BBL	170	178
(6)	Steam	1,000 BBL	3	0
(7)	CC	1,000 BBL	93	51
(8)	CT	1,000 BBL	75	127
(9)	Natural Gas - Total	1,000 MCF	764,300	742,232
(10)	Steam	1,000 MCF	23,774	26,133
(11)	CC	1,000 MCF	700,054	697,665
(12)	CC PPAs - Gas [2/]	1,000 MCF	29,041	0
(13)	CT	1,000 MCF	11,432	18,434
(14)	Hydrogen [3/]	Trillion BTU	0.002	0.10
(15)	Other [4/]	1,000 MCF	189	160

1/ Source: A Schedules.
2/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.
3/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
4/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

**Schedule 5: Forecasted
Fuel Requirements**

Fuel Requirements	Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
		Forecasted									
						FPL					
(1) Nuclear	Trillion BTU	303	300	302	308	306	307	306	308	306	307
(2) Coal	1,000 TON	271	302	406	326	360	359	352	368	433	466
(3) Residual (FO_6) - Total	1,000 BBL	0	0	0	0	0	2	9	0	0	0
(4) Steam	1,000 BBL	0	0	0	0	0	2	9	0	0	0
(5) Distillate (FO_2) - Total	1,000 BBL	8	10	8	9	8	8	4	5	5	2
(6) Steam	1,000 BBL	8	10	8	9	7	8	4	5	5	2
(7) CC	1,000 BBL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CT	1,000 BBL	0.0	0.6	0.2	0.0	1.7	0.0	0.0	0.0	0.0	0.0
(9) Natural Gas - Total	1,000 MCF	672,979	667,530	647,617	638,954	628,378	611,221	583,085	561,314	551,144	523,465
(10) Steam	1,000 MCF	19,690	20,424	15,957	16,199	14,835	14,784	13,172	10,919	13,078	12,002
(11) CC	1,000 MCF	644,888	639,487	625,959	618,308	609,660	591,392	565,784	546,151	532,868	507,689
(12) CC PPAs - Gas 2/	1,000 MCF	0	0	0	0	0	0	0	0	0	0
(13) CT	1,000 MCF	8,401	7,619	5,702	4,448	3,882	5,044	4,129	4,245	5,198	3,775
(14) Hydrogen 3/	1,000 MCF	0	0	0	0	0	0	0	0	0	0
(15) Other 4/	1,000 MCF	258	260	260	261	260	0	0	0	0	0

1/ Source: A Schedules.
2/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.
3/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program - FPL does not include Hydrogen in it's forecasted fuel requirements.
4/ Perdido Units' landfill gas burn included in Other
Note: Solar contributions are provided on Schedules 6.1 and 6.2.

Schedule 6.1 Actual
Energy Sources

	Energy Sources	Units	Actual [1/] FPL 2023	Actual [1/] FPL 2024
(1)	Annual Energy Interchange [2/]	GWH	0	0
(2)	Nuclear	GWH	28,767	28,009
(3)	Coal	GWH	472	533
(4)	Residual(FO_6) -Total	GWH	0.0	0.0
(5)	Steam	GWH	0	0
(6)	Distillate(FO_2) -Total	GWH	233.2	116.4
(7)	Steam	GWH	7	9
(8)	CC	GWH	79	43
(9)	CT	GWH	147	64
(10)	Natural Gas -Total	GWH	105,854	104,335
(11)	Steam	GWH	1,870	2,074
(12)	CC	GWH	101,578	100,515
(13)	CC PPAs - Gas [3/]	GWH	1,367	0
(14)	CT	GWH	1,040	1,747
(15)	Solar [4/]	GWH	9,460	12,404
(16)	PV	GWH	6,253	6,929
(17)	Solar Together [5/]	GWH	2,992	5,260
(18)	Solar PPAs	GWH	215	215
(19)	Wind PPAs	GWH	1,029	1,029
(20)	Hydrogen Gas [6/]	GWH	0.36	16
(21)	Other [7/]	GWH	(2,060)	(356)
	Net Energy For Load [8/]	GWH	143,756	146,103

1/ Sources: Actuals for FPL and FPL NWFL: A Schedules and Actual Data for Next Generation Solar Centers Report.

2/ Represents interchange between FPL/FPL NWFL and other utilities. For FPL NW, this number represents the net energy exchange with Southern Co.

3/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.

4/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.

5/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.

6/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program

7/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the LFG generation from the Perdido unit.

8/ 'Net Energy For Load values for the years 2023 and 2024 are shown in column (2) on Schedule 3.3 History of Annual Net Energy for Load

Schedule 6.1 Forecasted
Energy Sources

	Energy Sources	Units	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
							FPL					
(1)	Annual Energy Interchange 1/	GWH	0	0	0	0	0	0	0	0	0	0
(2)	Nuclear	GWH	28,750	28,504	28,610	29,223	29,032	29,135	29,029	29,219	29,029	29,136
(3)	Coal	GWH	421	472	643	513	569	565	553	580	684	738
(4)	Residual(FO_6) -Total	GWH	0	0	0	0	0	2	0	0	11	0
(5)	Steam	GWH	0	0	0	0	0	2	6	0	0	0
(6)	Distillate(FO_2) -Total	GWH	4	6	4	3	2	3	2	2	2	1
(7)	Steam	GWH	3	4	3	3	2	3	2	2	2	1
(8)	CC	GWH	0	0	0	0	0	0	0	0	0	0
(9)	CT	GWH	1	2	1	0	0	0	0	0	0	0
(10)	Natural Gas -Total	GWH	94,814	93,777	92,577	91,462	90,046	86,919	82,865	79,789	76,982	73,448
(11)	Steam	GWH	1,826	1,900	1,487	1,514	1,387	1,383	1,228	1,020	1,222	1,125
(12)	CC	GWH	92,206	91,163	90,552	89,532	88,294	85,059	81,262	78,370	75,267	71,967
(13)	CC PPAs - Gas 2/	GWH	0	0	0	0	0	0	0	0	0	0
(14)	CT	GWH	782	713	538	416	365	476	375	399	493	356
(15)	Solar 3/	GWH	17,692	19,662	21,736	25,140	29,159	34,294	39,720	45,254	50,328	55,800
(16)	PV	GWH	10,206	12,178	14,279	17,691	21,753	26,914	32,375	37,920	43,109	48,577
(17)	Solar Together 4/	GWH	7,266	7,264	7,238	7,230	7,188	7,163	7,129	7,119	7,012	7,012
(18)	Solar PPAs	GWH	220	220	219	219	218	217	216	215	207	210
(19)	Wind PPAs	GWH	1,031	1,031	1,031	1,033	1,031	1,031	1,031	1,033	1,031	1,031
(20)	Hydrogen Gas 5/	GWH	0	0	0	0	0	0	0	0	0	0
(21)	Other 6/	GWH	2,055	1,453	1,277	1,160	1,110	1,145	1,175	851	854	319
	Net Energy For Load 7/	GWH	144,793	144,931	145,905	148,562	150,976	153,094	154,375	156,728	158,922	160,473

1/ Represents interchange between FPL and other utilities.
2/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.
3/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.
5/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
6/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the Perdido Unit projected generation.
7/ Net Energy For Load values for the years 2023 and 2024 are shown in column (2) on Schedule 3.3 History of Annual Net Energy for Load and values for 2025 - 2034 are shown in Col. (2) on Schedule 3.3 Forecast of Annual Net Energy for Load.

Schedule 6.2 Actual
Energy Sources % by Fuel Type

	Energy Source	Units	Actual [1/] FPL 2023	Actual [1/] FPL 2024
(1)	Annual Energy Interchange [2/]	%	0.0	0.0
(2)	Nuclear	%	20.0	19.2
(3)	Coal	%	0.3	0.4
(4)	Residual (FO_6) -Total	%	0.0	0.0
(5)	Steam	%	0.0	0.0
(6)	Distillate (FO_2) -Total	%	0.2	0.1
(7)	Steam	%	0.0	0.0
(8)	CC	%	0.1	0.0
(9)	CT	%	0.1	0.0
(10)	Natural Gas -Total	%	73.6	71.4
(11)	Steam	%	1.3	1.4
(12)	CC	%	70.7	68.8
(13)	CC PPAs - Gas [3/]	%	1.0	0.0
(14)	CT	%	0.7	1.2
(15)	Solar [4/]	%	6.6	8.5
(16)	PV	%	4.3	4.7
(17)	Solar Together [5/]	%	2.1	3.6
(18)	Solar PPAs	%	0.1	0.1
(19)	Wind PPAs	%	0.7	0.7
(20)	Hydrogen Gas [6/]	%	0.0	0.0
(21)	Other [7/]	%	(1.4)	(0.2)
			100	100

1/ Sources: Actuals for FPL and FPL NWFL: A Schedules and Actual Data for Next Generation Solar Centers Report.

2/ Represents interchange between FPL/FPL NWFL and other utilities. For FPL NW, this number represents the net energy exchange with Southern Co.

3/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.

4/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.

5/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.

6/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program

7/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the LFG generation from the Perdido unit.

Schedule 6.2 Forecasted
Energy Sources % by Fuel Type

		FPL									
Energy Source	**Units**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
(1) Annual Energy Interchange 1/	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.9	19.7	19.6	19.7	19.2	19.0	18.8	18.6	18.3	18.2
(3) Coal	%	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.5
(4) Residual (FO_6) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6) Distillate (FO_2) -Total	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	65.5	64.7	63.5	61.6	59.6	56.8	53.7	50.9	48.4	45.8
(11) Steam	%	1.3	1.3	1.0	1.0	0.9	0.9	0.8	0.7	0.8	0.7
(12) CC	%	63.7	62.9	62.1	60.3	58.5	55.6	52.6	50.0	47.4	44.8
(13) CC PPAs - Gas 2/	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(14) CT	%	0.5	0.5	0.4	0.3	0.2	0.3	0.2	0.3	0.3	0.2
(15) Solar 3/	%	12.2	13.6	14.9	16.9	19.3	22.4	25.7	28.9	31.7	34.8
(16) PV	%	7.0	8.4	9.8	11.9	14.4	17.6	21.0	24.2	27.1	30.3
(17) Solar Together 4/	%	5.0	5.0	5.0	4.9	4.8	4.7	4.6	4.5	4.4	4.4
(18) Solar PPAs	%	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(19) Wind PPAs	%	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6
(20) Hydrogen Gas 5/	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(21) Other 6/	%	1.4	1.0	0.9	0.8	0.7	0.7	0.8	0.5	0.5	0.2
		100	100	100	100	100	100	100	100	100	100

1/ Represents interchange between FPL and other utilities.
2/ The Natural Gas PPA that we had with the Shell Plant was retired at the end of 2023.
3/ Represents output from FPL and FPL NWFL's Solar PV, Solar Together (ST), Solar Thermal, and Solar PPA facilities.
4/ The values shown represent energy produced from FPL-owned solar facilities that are part of FPL's SolarTogether (ST) program. Environmental attributes in the form of renewable energy certificates for that participant's allocation of the total energy produced are retired on the participant's behalf.
5/ Represents the Hydrogen Gas produced from the Okeechobee H2 Pilot Program
6/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, etc., net of Economy and other Power Sales as well as the Perdido Unit projected generation.

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
2025	31,971	232	0	4	32,206	28,312	1,995	26,317	5,889	22.4	0	5,889	22.4	3,894	13.8
2026	32,838	231	0	4	33,073	28,664	2,016	26,648	6,425	24.1	0	6,425	24.1	4,409	15.4
2027	33,970	231	0	0	34,201	28,925	2,036	26,888	7,313	27.2	0	7,313	27.2	5,276	18.2
2028	34,312	231	0	0	34,543	29,333	2,056	27,277	7,266	26.6	0	7,266	26.6	5,210	17.8
2029	34,637	231	0	0	34,869	29,687	2,079	27,608	7,261	26.3	0	7,261	26.3	5,182	17.5
2030	34,830	231	0	0	35,061	29,982	2,106	27,877	7,184	25.8	0	7,184	25.8	5,079	16.9
2031	35,180	231	0	0	35,411	30,301	2,133	28,168	7,242	25.7	0	7,242	25.7	5,109	16.9
2032	35,753	191	0	0	35,944	30,823	2,161	28,662	7,282	25.4	0	7,282	25.4	5,121	16.6
2033	36,282	191	0	0	36,472	31,257	2,189	29,068	7,404	25.5	0	7,404	25.5	5,215	16.7
2034	36,735	121	0	0	36,856	31,677	2,217	29,460	7,396	25.1	0	7,396	25.1	5,179	16.3

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2024-on intended for use with the 2025 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 7.2
Forecast of Capacity, Demand, and Scheduled Maintenance At Time Of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
2025	29,898	449	0	4	30,351	23,042	1,514	21,527	8,823	41.0	0	8,823	41.0	7,309	31.7
2026	30,451	219	0	4	30,674	23,323	1,523	21,800	8,874	40.7	0	8,874	40.7	7,350	31.5
2027	31,924	219	0	0	32,143	23,648	1,532	22,116	10,027	45.3	0	10,027	45.3	8,495	35.9
2028	33,046	219	0	0	33,265	24,136	1,542	22,594	10,672	47.2	0	10,672	47.2	9,130	37.8
2029	33,687	219	0	0	33,906	24,603	1,550	23,053	10,853	47.1	0	10,853	47.1	9,302	37.8
2030	33,887	219	0	0	34,106	25,011	1,565	23,446	10,660	45.5	0	10,660	45.5	9,095	36.4
2031	34,546	219	0	0	34,765	25,384	1,580	23,804	10,961	46.0	0	10,961	46.0	9,381	37.0
2032	35,680	219	0	0	35,899	25,852	1,595	24,256	11,643	48.0	0	11,643	48.0	10,048	38.9
2033	35,743	179	0	0	35,922	26,245	1,611	24,634	11,288	45.8	0	11,288	45.8	9,678	36.9
2034	37,000	179	0	0	37,179	26,638	1,627	25,011	12,168	48.6	0	12,168	48.6	10,541	39.6

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the load forecast without incremental DSM or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental conservation and load management, from 9/2024-on intended for use with the 2025 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2/]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
			FPL											
2025														
Martin Upgrade	4	Martin County	CC	NG	No	PL	No	-	1st Q 2025	Unknown	520,000	9	-	OP
Sanford Upgrade	5	Volusia County	CC	NG	No	PL	No	-	1st Q 2025	Unknown	1,252,000	26	10	OP
Turkey Point Upgrade	5	Miami-Dade County	CC	NG	FO_2	PL	TK		2nd Q 2025	Unknown	1,358,000	3	8	OP
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(11)	OT
											2025 Changes/Additions Total:	**38**	**7**	
2026														
Pea Ridge Retirement	1	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Pea Ridge Retirement	2	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Pea Ridge Retirement	3	Santa Rosa	GT	NG	PL	NA	NA	-	May-98	2nd Q 2025	5,000	-	(4)	P
Gulf Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	4th Q 2025	Unknown	521,500	522	349	P
Flatford Solar [3/]	1	Manatee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	5	3	P
Mare Branch Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	23	P
Price Creek Solar [3/]	1	Columbia County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	0	6	P
Swamp Cabbage Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	3	22	P
Big Brook Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	0	21	P
Mallard Solar [3/]	1	Brevard County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	4	P
Boardwalk Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	9	P
Goldenrod Solar [3/]	1	Collier County	PV	Solar	Solar	N/A	N/A	-	1st Q 2026	Unknown	74,500	2	4	P
North Orange Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	4	P
Sea Grape Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	2	4	P
Clover Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	3	4	P
Sand Pine Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2026	Unknown	74,500	0	10	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2026	Unknown	1,419,500	1,420	997	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(12)	OT
											2026 Changes/Additions Total:	**1,966**	**1,435**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan
Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2/]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
FPL														
2027														
Hendry Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Tangelo Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Wood Stork Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
Indrio Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	1st Q 2027	Unknown	74,500	2	4	P
West County Upgrade	1	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
West County Upgrade	2	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
West County Upgrade	3	Palm Beach County	CC	NG	FO_2	PL	TK	-	1st Q 2027	Unknown	1,349,000	9	-	OP
Middle Lake Solar [3/]	1	Madison County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Ambersweet Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
County Line Solar [3/]	1	Charlotte, DeSoto County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Saddle Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	2nd Q 2027	Unknown	74,500	2	4	P
Manatee Upgrade	3	Manatee Country	CC	NG	No	PL	No	-	2nd Q 2027	Unknown	1,346,000	5	29	OP
Martin Upgrade	8	Martin County	CC	NG	FO_2	PL	TK	-	2nd Q 2027	Unknown	1,327,000	5	19	OP
Cocoplum Solar [3/]	1	Hendry County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Catfish Solar [3/]	1	Okeechobee County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Hardwood Hammock Solar [3/]	1	Walton County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Maple Trail Solar [3/]	1	Baker County	PV	Solar	Solar	N/A	N/A	-	3rd Q 2027	Unknown	74,500	2	4	P
Pinecone Solar [3/]	1	Calhoun County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Joshua Creek Solar [3/]	1	DeSoto County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Spanish Moss Solar [3/]	1	St. Lucie County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Vernia Solar [3/]	1	Indian River County	PV	Solar	Solar	N/A	N/A	-	4th Q 2027	Unknown	74,500	2	4	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2027	Unknown	819,500	820	432	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(12)	OT
											2027 Changes/Additions Total:	**896**	**531**	
2028														
Lansing Smith Retirement	3A	Broward County	CT	LO	--	TK	--	-	May-71	4th Q 2027	40,000	(40)	(32)	P
Manatee Upgrade	3	Manatee Country	CC	NG	No	PL	No		1st Q 2028	Unknown	1,346,000	3	14	OP
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2028	Unknown	1,490,000	0	79	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2028	Unknown	596,000	596	298	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2028 Changes/Additions Total:	**559**	**346**	
2029														
Gulf Clean Energy Center Retirement	4	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Gulf Clean Energy Center Retirement	5	Escambia County	ST	NG	--	PL	--	-	Jun-61	4th Q 2029	75,000	(75)	(75)	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2029	Unknown	596,000	596	247	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2029	Unknown	1,788,000	0	95	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2029 Changes/Additions Total:	**446**	**179**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes achieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 8 - Resource Plan

Planned And Prospective Generating Facility Additions And Changes [1/] : FPL

	(2)	(3)	(4)	(5)	(5)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Transport		Const.	Comm.	Expected	Gen. Max.	Firm Net Capability [2/]		
Plant Name	Unit No.	Location	Unit Type	Pri.	Alt.	Pri.	Alt.	Start Mo./Yr.	In-Service Mo./Yr.	Retirement Mo./Yr.	Nameplate KW	Winter MW	Summer MW	Status
ADDITIONS/ CHANGES														
FPL														
2030														
Perdido Retirement	1	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Perdido Retirement	2	Escambia County	IC	LFG	-	PL	-	-	Oct-10	4th Q 2029	1,500	(2)	(2)	P
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2030	Unknown	596,000	596	244	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2030	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(13)	OT
											2030 Changes/Additions Total:	**593**	**347**	
2031														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2031	Unknown	596,000	596	244	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2031	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2031 Changes/Additions Total:	**596**	**349**	
2032														
2x0 Manatee CT	1	Manatee County	CT	NG	-	PL	-	-	1st Q 2032	Unknown	475,000	475	469	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2032	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2032 Changes/Additions Total:	**475**	**574**	
2033														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2033	Unknown	1,192,000	1,192	424	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2033	Unknown	2,235,000	0	119	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(14)	OT
											2033 Changes/Additions Total:	**1,192**	**528**	
2034														
Battery Storage [4/]	1	Unknown	BS	N/A	N/A	N/A	N/A	-	1st Q 2034	Unknown	1,267,000	1,267	350	P
Solar PV [3/]	1	Unknown	PV	Solar	Solar	N/A	N/A	-	1st Q 2034	Unknown	2,235,000	0	119	P
Scherer Retirement	3	Monroe County, GA	FS	C	-	RR	-	-	Jan-87	4th Q 2034	215,000	(215)	(215)	P
Solar Degradation [3/]	N/A	N/A	N/A	N/A	N/A	N/A	N/A	-	N/A	N/A	N/A	-	(15)	OT
											2034 Changes/Additions Total:	**1,052**	**239**	

1/ Schedule 8 shows only planned and prospective changes to FPL generating facilities and does not reflect changes to purchases. Changes to purchases are reflected on Tables ES-1, I.A.3.1, and I.A.3.2

2/ The Winter Total MW value consists of all generation additions and changes achieved by January. The Summer Total MW value consists of all generation additions and changes hieved by June. All MW additions/changes occurring after June each year will be accounted for in reserve margin calculations in the following year. MW Difference in Changes/Additions Total due to rounding.

3/ Solar MW values reflect firm capacity only, not nameplate ratings and FPL currently assumes 0.35% degradation annually for PV output.

4/ Battery MW values reflect firm capacity only, not nameplate ratings.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Gulf Battery Storage (3-Hour Duration)

(2) **Capacity**

a. Nameplate (AC)	522	MW
b. Summer Firm (AC)	349	MW
c. Winter Firm (AC)	522	MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2024
b. Commercial In-service date: 4th Q 2025

(5) **Fuel**
a. Primary Fuel: Not applicable
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** This is a compilation of several BESS sites that will all be located at existing Solar sites.

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Round-Trip Efficiency	87.00%
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2025 $/kW):		1,031	
Direct Construction Cost ($/kW):		1,011	
AFUDC Amount (2025 $/kW):		19.80	
Escalation ($/kW):		Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.):	(2025 $)	0.90	(First Full Year Operation)
Variable O&M ($/MWH):	(2025 $)	0.00	
K Factor:		0.98	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.
2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Flatford Solar Energy Center (Manatee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	3 MW	
	c. Winter Firm (AC)	5 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2025	
	b. Commercial In-service date:	2026	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	925	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	27.70%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2026 $/kW):	1,721	
	Direct Construction Cost ($/kW):	1,639	
	AFUDC Amount (2026 $/kW):	83	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
	Variable O&M ($/MWH): (2026 $)	0.00	
	K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Mare Branch Solar Energy Center (DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 23 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 669 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.55% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 35 years
Total Installed Cost (2026 $/kW): 1,721
Direct Construction Cost ($/kW): 1,639
AFUDC Amount (2026 $/kW): 83
Escalation ($/kW): Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2026 $) 4.35 (First Full Year Operation)
Variable O&M ($/MWH): (2026 $) 0.00
K Factor: 1.11

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Price Creek Solar Energy Center (Columbia County)		
(2)	**Capacity**			
	a. Nameplate (AC)	74.5	MW	
	b. Summer Firm (AC)[1/]	6	MW	
	c. Winter Firm (AC)	0	MW	
(3)	**Technology Type:**	Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2025		
	b. Commercial In-service date:	2026		
(5)	**Fuel**			
	a. Primary Fuel	Solar		
	b. Alternate Fuel	Not applicable		
(6)	**Air Pollution and Control Strategy:**	Not applicable		
(7)	**Cooling Method:**	Not applicable		
(8)	**Total Site Area:**	792	Acres	
(9)	**Construction Status:**	P	(Planned Unit)	
(10)	**Certification Status:**	---		
(11)	**Status with Federal Agencies:**	---		
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):	Not applicable		
	Forced Outage Factor (FOF):	Not applicable		
	Equivalent Availability Factor (EAF):	Not applicable		
	Resulting Capacity Factor (%):	27.79%	(First Full Year Operation)	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable		
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable		
(13)	**Projected Unit Financial Data ***			
	Book Life (Years):		35 years	
	Total Installed Cost (2026 $/kW):		1,721	
	Direct Construction Cost ($/kW):		1,639	
	AFUDC Amount (2026 $/kW):		83	
	Escalation ($/kW):		Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.):	(2026 $)	4.35	(First Full Year Operation)
	Variable O&M ($/MWH):	(2026 $)	0.00	
	K Factor:		1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Swamp Cabbage Solar Energy Center (Hendry County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	22	MW
	c. Winter Firm (AC)	3	MW
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2025	
	b. Commercial In-service date:	2026	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	725	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	27.14%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2026 $/kW):	1,721	
	Direct Construction Cost ($/kW):	1,639	
	AFUDC Amount (2026 $/kW):	83	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
	Variable O&M ($/MWH): (2026 $)	0.00	
	K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Big Brook Solar Energy Center (Calhoun County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	21	MW
	c. Winter Firm (AC)	-	MW
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2025	
	b. Commercial In-service date:	2026	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	848	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	29.05%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	35	years
	Total Installed Cost (2026 $/kW):	1,721	
	Direct Construction Cost ($/kW):	1,639	
	AFUDC Amount (2026 $/kW):	83	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
	Variable O&M ($/MWH): (2026 $)	0.00	
	K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Mallard Solar Energy Center (Brevard County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 456 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Resulting Capacity Factor (%):	28.30% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data** *

Book Life (Years):	35 years	
Total Installed Cost (2026 $/kW):	1,721	
Direct Construction Cost ($/kW):	1,639	
AFUDC Amount (2026 $/kW):	83	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
Variable O&M ($/MWH): (2026 $)	0.00	
K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Boardwalk Solar Energy Center (Collier County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 9 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 553 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.98% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2026 $/kW): 1,721
Direct Construction Cost ($/kW): 1,639
AFUDC Amount (2026 $/kW): 83
Escalation ($/kW): Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2026 $) 4.35 (First Full Year Operation)
Variable O&M ($/MWH): (2026 $) 0.00
K Factor: 1.11

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Goldenrod Solar Energy Center (Collier County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	4	MW
c. Winter Firm (AC)	2	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel: Solar
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 610 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Resulting Capacity Factor (%):	29.11% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years
Total Installed Cost (2026 $/kW):		1,721
Direct Construction Cost ($/kW):		1,639
AFUDC Amount (2026 $/kW):		83
Escalation ($/kW):		Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.):	(2026 $)	4.35 (First Full Year Operation)
Variable O&M ($/MWH):	(2026 $)	0.00
K Factor:		1.11

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	North Orange Solar Energy Center (St. Lucie County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	3 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2025	
	b. Commercial In-service date:	2026	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	656	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.41%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2026 $/kW):	1,721	
	Direct Construction Cost ($/kW):	1,639	
	AFUDC Amount (2026 $/kW):	83	
	Escalation ($/kW):	Accounted for in Direct Construction Cost	
	Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
	Variable O&M ($/MWH): (2026 $)	0.00	
	K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sea Grape Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 564 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.47% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2026 $/kW): 1,721
Direct Construction Cost ($/kW): 1,639
AFUDC Amount (2026 $/kW): 83
Escalation ($/kW): Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2026 $) 4.35 (First Full Year Operation)
Variable O&M ($/MWH): (2026 $) 0.00
K Factor: 1.11

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Clover Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 3 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 433 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	28.47%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):	35 years	
Total Installed Cost (2026 $/kW):	1,721	
Direct Construction Cost ($/kW):	1,639	
AFUDC Amount (2026 $/kW):	83	
Escalation ($/kW):	Accounted for in Direct Construction Cost	
Fixed O&M ($/kW-Yr.): (2026 $)	4.35	(First Full Year Operation)
Variable O&M ($/MWH): (2026 $)	0.00	
K Factor:	1.11	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sand Pine Solar Energy Center (Calhoun County)

(2) **Capacity**

a. Nameplate (AC)	74.5	MW
b. Summer Firm (AC)[1/]	10	MW
c. Winter Firm (AC)	-	MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2025
b. Commercial In-service date: 2026

(5) **Fuel**
a. Primary Fuel: Solar
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 719 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Resulting Capacity Factor (%):	27.62% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):	35 years
Total Installed Cost (2026 $/kW):	1,721
Direct Construction Cost ($/kW):	1,639
AFUDC Amount (2026 $/kW):	83
Escalation ($/kW):	Accounted for in Direct Construction Cost
Fixed O&M ($/kW-Yr.): (2026 $)	4.35 (First Full Year Operation)
Variable O&M ($/MWH): (2026 $)	0.00
K Factor:	1.11

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Battery Storage (4-Hour Duration)	
(2)	**Capacity**		
	a. Nameplate (AC)	1,420	MW
	b. Summer Firm (AC)	997	MW
	c. Winter Firm (AC)	1,420	MW
(3)	**Technology Type:**	Battery	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2025	
	b. Commercial In-service date:	2026	
(5)	**Fuel**		
	a. Primary Fuel	Not applicable	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Round-Trip Efficiency	88.00%	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	20 years	
	Total Installed Cost (2026 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2026 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2026 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2026 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Hendry Solar Energy Center (Hendry County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	641	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Tangelo Solar Energy Center (Okeechobee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5	MW
	b. Summer Firm (AC)[1/]	4	MW
	c. Winter Firm (AC)	2	MW
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	748	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Wood Stork Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 603 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2027 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2027 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2027 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2027 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Indrio Solar Energy Center (St. Lucie County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	400	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Middle Lake Solar Energy Center (Madison County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 524 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Resulting Capacity Factor (%):	28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2027 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2027 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Ambersweet Solar Energy Center (Indian River County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 518 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2027 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2027 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2027 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2027 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** County Line Solar Energy Center (Charlotte/DeSoto County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel: Solar
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 630 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2027 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2027 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2027 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2027 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Saddle Solar Energy Center (DeSoto County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	647	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Cocoplum Solar Energy Center (Hendry County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	470	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Catfish Solar Energy Center (Okeechobee County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	837	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Hardwood Hammock Solar Energy Center (Walton County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)1/	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	750	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Maple Trail Solar Energy Center (Baker County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)[1/] 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 930 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):		35 years	
Total Installed Cost (2027 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2027 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2027 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2027 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Pinecone Solar Energy Center (Calhoun County)		
(2)	**Capacity**			
	a. Nameplate (AC)	74.5	MW	
	b. Summer Firm (AC)[1/]	4	MW	
	c. Winter Firm (AC)	2	MW	
(3)	**Technology Type:**	Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2026		
	b. Commercial In-service date:	2027		
(5)	**Fuel**			
	a. Primary Fuel	Solar		
	b. Alternate Fuel	Not applicable		
(6)	**Air Pollution and Control Strategy:**	Not applicable		
(7)	**Cooling Method:**	Not applicable		
(8)	**Total Site Area:**	438	Acres	
(9)	**Construction Status:**	P	(Planned Unit)	
(10)	**Certification Status:**	---		
(11)	**Status with Federal Agencies:**	---		
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):	Not applicable		
	Forced Outage Factor (FOF):	Not applicable		
	Equivalent Availability Factor (EAF):	Not applicable		
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable		
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable		
(13)	**Projected Unit Financial Data ***			
	Book Life (Years):	35 years		
	Total Installed Cost (2027 $/kW):	TBD		
	Direct Construction Cost ($/kW):	TBD		
	AFUDC Amount (2027 $/kW):	TBD		
	Escalation ($/kW):	TBD		
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)	
	Variable O&M ($/MWH): (2027 $)	TBD		
	K Factor:	TBD		

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Joshua Creek Solar Energy Center (DeSoto County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	621	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

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Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Spanish Moss Solar Energy Center (St. Lucie County)

(2) **Capacity**
a. Nameplate (AC) 74.5 MW
b. Summer Firm (AC)1/ 4 MW
c. Winter Firm (AC) 2 MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2026
b. Commercial In-service date: 2027

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** 483 Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): 28.59% (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2027 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2027 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2027 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2027 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Vernia Solar Energy Center (Indian River County)	
(2)	**Capacity**		
	a. Nameplate (AC)	74.5 MW	
	b. Summer Firm (AC)[1/]	4 MW	
	c. Winter Firm (AC)	2 MW	
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	533	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	28.59%	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	35 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9

Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Battery Storage (4-Hour Duration)	
(2)	**Capacity**		
	a. Nameplate (AC)	819.5 MW	
	b. Summer Firm (AC)	432 MW	
	c. Winter Firm (AC)	819.5 MW	
(3)	**Technology Type:**	Battery	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2026	
	b. Commercial In-service date:	2027	
(5)	**Fuel**		
	a. Primary Fuel	Not applicable	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Round-Trip Efficiency	88.00%	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	20 years	
	Total Installed Cost (2027 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2027 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2027 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2027 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL w ill continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Solar PV		
(2)	**Capacity**			
	a. Nameplate (AC)	1,490	MW	
	b. Summer Firm (AC)[1/]	79	MW	
	c. Winter Firm (AC)	-	MW	
(3)	**Technology Type:**	Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2027		
	b. Commercial In-service date:	2028		
(5)	**Fuel**			
	a. Primary Fuel	Solar		
	b. Alternate Fuel	Not applicable		
(6)	**Air Pollution and Control Strategy:**	Not applicable		
(7)	**Cooling Method:**	Not applicable		
(8)	**Total Site Area:**	748	Acres	
(9)	**Construction Status:**	P	(Planned Unit)	
(10)	**Certification Status:**	---		
(11)	**Status with Federal Agencies:**	---		
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):	Not applicable		
	Forced Outage Factor (FOF):	Not applicable		
	Equivalent Availability Factor (EAF):	Not applicable		
	Resulting Capacity Factor (%):	TBD	(First Full Year Operation)	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable		
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable		
(13)	**Projected Unit Financial Data ***			
	Book Life (Years):	35 years		
	Total Installed Cost (2028 $/kW):	TBD		
	Direct Construction Cost ($/kW):	TBD		
	AFUDC Amount (2028 $/kW):	TBD		
	Escalation ($/kW):	TBD		
	Fixed O&M ($/kW-Yr.): (2028 $)	TBD	(First Full Year Operation)	
	Variable O&M ($/MWH): (2028 $)	TBD		
	K Factor:	TBD		

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Battery Storage (4-Hour Duration)	
(2)	**Capacity**		
	a. Nameplate (AC)	596 MW	
	b. Summer Firm (AC)	298 MW	
	c. Winter Firm (AC)	596 MW	
(3)	**Technology Type:**	Battery	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2027	
	b. Commercial In-service date:	2028	
(5)	**Fuel**		
	a. Primary Fuel	Not applicable	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Round-Trip Efficiency	TBD	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	20 years	
	Total Installed Cost (2028 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2028 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2028 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2028 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Solar PV

(2) **Capacity**
a. Nameplate (AC) 1,788 MW
b. Summer Firm (AC)1/ 95 MW
c. Winter Firm (AC) - MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2028
b. Commercial In-service date: 2029

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2029 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2029 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2029 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2029 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL w ill continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Battery Storage (4-Hour Duration)	
(2)	**Capacity**		
	a. Nameplate (AC)	596	MW
	b. Summer Firm (AC)	247	MW
	c. Winter Firm (AC)	596	MW
(3)	**Technology Type:**	Battery	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2028	
	b. Commercial In-service date:	2029	
(5)	**Fuel**		
	a. Primary Fuel	Not applicable	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Round-Trip Efficiency	TBD	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	20 years	
	Total Installed Cost (2029 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2029 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2029 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2029 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL w ill continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Solar PV		
(2)	**Capacity**			
	a. Nameplate (AC)	2,235	MW	
	b. Summer Firm (AC)[1/]	119	MW	
	c. Winter Firm (AC)	-	MW	
(3)	**Technology Type:**	Photovoltaic (PV)		
(4)	**Anticipated Construction Timing**			
	a. Field construction start-date:	2029		
	b. Commercial In-service date:	2030		
(5)	**Fuel**			
	a. Primary Fuel	Solar		
	b. Alternate Fuel	Not applicable		
(6)	**Air Pollution and Control Strategy:**	Not applicable		
(7)	**Cooling Method:**	Not applicable		
(8)	**Total Site Area:**	TBD	Acres	
(9)	**Construction Status:**	P	(Planned Unit)	
(10)	**Certification Status:**	---		
(11)	**Status with Federal Agencies:**	---		
(12)	**Projected Unit Performance Data:**			
	Planned Outage Factor (POF):	Not applicable		
	Forced Outage Factor (FOF):	Not applicable		
	Equivalent Availability Factor (EAF):	Not applicable		
	Resulting Capacity Factor (%):	TBD	(First Full Year Operation)	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable		
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable		
(13)	**Projected Unit Financial Data** *			
	Book Life (Years):		35 years	
	Total Installed Cost (2030 $/kW):		TBD	
	Direct Construction Cost ($/kW):		TBD	
	AFUDC Amount (2030 $/kW):		TBD	
	Escalation ($/kW):		TBD	
	Fixed O&M ($/kW-Yr.):	(2030 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH):	(2030 $)	TBD	
	K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Battery Storage (4-Hour Duration)

(2) **Capacity**

a. Nameplate (AC)	596	MW
b. Summer Firm (AC)	244	MW
c. Winter Firm (AC)	596	MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2029
b. Commercial In-service date: 2030

(5) **Fuel**
a. Primary Fuel Not applicable
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Round-Trip Efficiency	TBD
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2030 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2030 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2030 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2030 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.
2/ FPL w ill continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Solar PV

(2) **Capacity**
a. Nameplate (AC) 2,235 MW
b. Summer Firm (AC)[1/] 119 MW
c. Winter Firm (AC) - MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2030
b. Commercial In-service date: 2031

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable	
Forced Outage Factor (FOF):	Not applicable	
Equivalent Availability Factor (EAF):	Not applicable	
Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	

(13) **Projected Unit Financial Data ***

Book Life (Years):	35 years	
Total Installed Cost (2031 $/kW):	TBD	
Direct Construction Cost ($/kW):	TBD	
AFUDC Amount (2031 $/kW):	TBD	
Escalation ($/kW):	TBD	
Fixed O&M ($/kW-Yr.): (2031 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH): (2031 $)	TBD	
K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Battery Storage (4-Hour Duration)

(2) **Capacity**

a. Nameplate (AC)	596	MW
b. Summer Firm (AC)	244	MW
c. Winter Firm (AC)	596	MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2030
b. Commercial In-service date: 2031

(5) **Fuel**
a. Primary Fuel Not applicable
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Round-Trip Efficiency	TBD
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2031 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2031 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2031 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2031 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.
2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	2x0 Manatee CT	
(2)	**Capacity**		
	a. Nameplate (AC)	475 MW	
	b. Summer Firm (AC)[1/]	469 MW	
	c. Winter Firm (AC)	475 MW	
(3)	**Technology Type:**	Combustion Turbine	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2028	
	b. Commercial In-service date:	2032	
(5)	**Fuel**		
	a. Primary Fuel	Natural Gas	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	TBD	
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data ***		
	Book Life (Years):	50 years	
	Total Installed Cost (2032 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2032 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2032 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2032 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1)	**Plant Name and Unit Number:**	Unsited Solar PV	
(2)	**Capacity**		
	a. Nameplate (AC)	2,235	MW
	b. Summer Firm (AC)[1/]	119	MW
	c. Winter Firm (AC)	-	MW
(3)	**Technology Type:**	Photovoltaic (PV)	
(4)	**Anticipated Construction Timing**		
	a. Field construction start-date:	2031	
	b. Commercial In-service date:	2032	
(5)	**Fuel**		
	a. Primary Fuel	Solar	
	b. Alternate Fuel	Not applicable	
(6)	**Air Pollution and Control Strategy:**	Not applicable	
(7)	**Cooling Method:**	Not applicable	
(8)	**Total Site Area:**	TBD	Acres
(9)	**Construction Status:**	P	(Planned Unit)
(10)	**Certification Status:**	---	
(11)	**Status with Federal Agencies:**	---	
(12)	**Projected Unit Performance Data:**		
	Planned Outage Factor (POF):	Not applicable	
	Forced Outage Factor (FOF):	Not applicable	
	Equivalent Availability Factor (EAF):	Not applicable	
	Resulting Capacity Factor (%):	TBD	(First Full Year Operation)
	Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable	
	Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable	
(13)	**Projected Unit Financial Data** *		
	Book Life (Years):	35 years	
	Total Installed Cost (2032 $/kW):	TBD	
	Direct Construction Cost ($/kW):	TBD	
	AFUDC Amount (2032 $/kW):	TBD	
	Escalation ($/kW):	TBD	
	Fixed O&M ($/kW-Yr.): (2032 $)	TBD	(First Full Year Operation)
	Variable O&M ($/MWH): (2032 $)	TBD	
	K Factor:	TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.

2/ FPL w ill continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Solar PV

(2) **Capacity**
a. Nameplate (AC) 2,235 MW
b. Summer Firm (AC)[1/] 119 MW
c. Winter Firm (AC) - MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2032
b. Commercial In-service date: 2033

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data ***
Book Life (Years): 35 years
Total Installed Cost (2033 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2033 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2033 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2033 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value show n represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL w ill continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning w ork.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Battery Storage (4-Hour Duration)

(2) **Capacity**
a. Nameplate (AC) 1,192 MW
b. Summer Firm (AC) 424 MW
c. Winter Firm (AC) 1,192 MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2032
b. Commercial In-service date: 2033

(5) **Fuel**
a. Primary Fuel Not applicable
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Round-Trip Efficiency	TBD
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2033 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2033 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2033 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2033 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.
2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Solar PV

(2) **Capacity**
a. Nameplate (AC) 2,235 MW
b. Summer Firm (AC) 119 MW
c. Winter Firm (AC) - MW

(3) **Technology Type:** Photovoltaic (PV)

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2033
b. Commercial In-service date: 2034

(5) **Fuel**
a. Primary Fuel Solar
b. Alternate Fuel Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): Not applicable
Forced Outage Factor (FOF): Not applicable
Equivalent Availability Factor (EAF): Not applicable
Resulting Capacity Factor (%): TBD (First Full Year Operation)
Average Net Operating Heat Rate (ANOHR): Not applicable
Base Operation 75F,100%
Average Net Incremental Heat Rate (ANIHR): Not applicable
Peak Operation 75F,100%

(13) **Projected Unit Financial Data** *
Book Life (Years): 35 years
Total Installed Cost (2034 $/kW): TBD
Direct Construction Cost ($/kW): TBD
AFUDC Amount (2034 $/kW): TBD
Escalation ($/kW): TBD
Fixed O&M ($/kW-Yr.): (2034 $) TBD (First Full Year Operation)
Variable O&M ($/MWH): (2034 $) TBD
K Factor: TBD

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this amount of incremental PV assuming the planned PV additions in prior years. As the amount of PV on FPL's system increases, the remaining Summer load not served by solar is altered so that the remaining Summer peak load moves to later in the day. Because the amount of solar energy diminishes in these later hours, the firm capacity value of the incremental solar is decreased.
2/ FPL will continue to analyze the projected impacts of increasing amounts of battery storage in its on-going resource planning work.

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Unsited Battery Storage (4-Hour Duration)

(2) **Capacity**

a. Nameplate (AC)	1,267	MW
b. Summer Firm (AC)[1/]	350	MW
c. Winter Firm (AC)	1,267	MW

(3) **Technology Type:** Battery

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2033
b. Commercial In-service date: 2034

(5) **Fuel**
a. Primary Fuel: Not applicable
b. Alternate Fuel: Not applicable

(6) **Air Pollution and Control Strategy:** Not applicable

(7) **Cooling Method:** Not applicable

(8) **Total Site Area:** TBD Acres

(9) **Construction Status:** P (Planned Unit)

(10) **Certification Status:** ---

(11) **Status with Federal Agencies:** ---

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	Not applicable
Forced Outage Factor (FOF):	Not applicable
Equivalent Availability Factor (EAF):	Not applicable
Round-Trip Efficiency	TBD
Average Net Operating Heat Rate (ANOHR): Base Operation 75F,100%	Not applicable
Average Net Incremental Heat Rate (ANIHR): Peak Operation 75F,100%	Not applicable

(13) **Projected Unit Financial Data ***

Book Life (Years):		20 years	
Total Installed Cost (2034 $/kW):		TBD	
Direct Construction Cost ($/kW):		TBD	
AFUDC Amount (2034 $/kW):		TBD	
Escalation ($/kW):		TBD	
Fixed O&M ($/kW-Yr.):	(2034 $)	TBD	(First Full Year Operation)
Variable O&M ($/MWH):	(2034 $)	TBD	
K Factor:		TBD	

* $/kW values are based on nameplate capacity.

Note: Total installed cost includes transmission interconnection and AFUDC.

1/ The value shown represents FPL's current projection of the firm capacity of this battery storage after the net load of the system and other battery storage being discharged. Because battery storage "flattens" the peak period, the firm capacity value of storage decreases as more battery storage is added to the system.

2/ FPL will continue to analyze the projected impacts of increasing amounts of PV in its on-going resource planning work.

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Canoe Battery Energy Storage System Center (Okaloosa County)

The Canoe Battery Energy Storage System Center will be connected to the transmission bus at Mink Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Mink Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Mink Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Blackwater Battery Energy Storage System Center (Santa Rosa County)

The Blackwater Battery Energy Storage System Center will be connected to the transmission bus at Rooster Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Rooster Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Rooster Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Chipola River Battery Energy Storage System Center (Calhoun County)

The Chipola River Battery Energy Storage System Center will be connected to the transmission bus at Melvin Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Melvin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Melvin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Fourmile Creek Battery Energy Storage System Center (Calhoun County)

The Fourmile Creek Battery Energy Storage System Center will be connected to the transmission bus at Quincy Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Quincy Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Quincy Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Tenmile Creek Battery Energy Storage System Center (Calhoun County)

The Tenmile Creek Battery Energy Storage System Center will be connected to the transmission bus at Tenmile Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Tenmile Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Tenmile Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Shirer Branch Battery Energy Storage System Center (Calhoun County)

The Shirer Branch Battery Energy Storage System Center will be connected to the transmission bus at Mayo Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Mayo Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Mayo Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Kayak Battery Energy Storage System Center (Okaloosa County)

The Kayak Battery Energy Storage System Center will be connected to the transmission bus at Kayak Substation. approximately 0.0 miles to connect the BESS.

(1) Point of Origin and Termination:	Kayak Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2025
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Kayak Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Flatford Solar Energy Center (Manatee County)

The Flatford Solar Energy Center will require bifurcating the new FPL Gridiron - Keentown 230 kV transmission line approximately 0.0 miles to connect a new Flatford substation and the solar PV inverter array.

(1) Point of Origin and Termination:	Gridiron - Lemur 230kV transmission line to the new Flatford Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Flatford Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Mare Branch Solar Energy Center (DeSoto County)

The Mare Branch Solar Energy Center will require extending a transmission line from the Whidden Substation approximately 7.0 miles to connect the new Stallion Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Whidden Substation to the new Stallion Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	Approximately 7.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Stallion Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Price Creek Solar Energy Center (Columbia County)

The Price Creek Solar Energy Center will require bifurcating the FPL Claude - Raven 230 kV transmission line approximately 0.0 miles to connect a new Madonna substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Claude - Raven 230 kV transmission line to new Madonna Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Madonna Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Swamp Cabbage Solar Energy Center (Hendry County)

The Swamp Cabbage Solar Energy Center will require bifurcating the FPL Alva - Witt 230 kV transmission line approximately 3.15 miles to connect a new Swamp substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Alva - Witt 230 kV transmission line to new Swamp Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	Approximately 3.15 miles double circuit
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Swamp Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Big Brook Solar Energy Center (Calhoun County)

The Big Brook Solar Energy Center will require bifurcating the FPL Melvin - Tenmile 230 kV transmission line approximately 0.0 miles to connect a new Song substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Melvin - Tenmile 230 kV transmission line to new Song Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Song Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Mallard Solar Energy Center (Brevard County)

The Mallard Solar Energy Center will require extending the transmission bus at Crayfish Substation approximately 0.7 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Crayfish Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.7 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Goodwin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Boardwalk Solar Energy Center (Collier County)

The Boardwalk Solar Energy Center will require extending the transmission bus at Puma Substation approximately 0.0 miles to connect a new Boardwalk substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Puma Substation
(2) Number of Lines:	0
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Goldenrod Solar Energy Center (Collier County)

The Goldenrod Solar Energy Center will require extending the transmission bus at Puma/Boardwalk Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Boardwalk Substation
(2) Number of Lines:	0
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Boardwalk Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

North Orange Solar Energy Center (St. Lucie County)

The North Orange Solar Energy Center will require bifurcating the new FPL Sunbreak - Morrow 230 kV transmission line approximately 0.0 miles to connect a new Apricot substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Morrow 230 kV transmission line to new Apricot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Apricot Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sea Grape Solar Energy Center (St. Lucie County)

The Sea Grape Solar Energy Center will require bifurcating the new FPL Sunbreak - Morrow 230 kV transmission line approximately 0.0 miles to connect a new Muscadine substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Morrow 230 kV transmission line to new Muscadine Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Muscadine Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Clover Solar Energy Center (St. Lucie County)

The Clover Solar Energy Center will require extending a transmission line from the new Sunbreak Substation approximately 2.0 miles to connect the new Clover Substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak Substation to the new Clover Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	Approximately 2 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Clover Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Sand Pine Solar Energy Center (Calhoun County)

The Sand Pine Solar Energy Center will require extending the transmission bus at Quincy Substation approximately 0.0 miles to connect a new Chinkapin substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Quincy Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Chinkapin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Hendry Solar Energy Center (Hendry County)

The Hendry Solar Energy Center will require extending the transmission bus at Ghost Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Ghost Substation
(2) Number of Lines:	0
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	500 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ghost Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Tangelo Solar Energy Center (Okeechobee County)

The Tangelo Solar Energy Center will require extending the transmission bus at Seville Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Seville Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Seville Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Wood Stork Solar Energy Center (St. Lucie County)

The Wood Stork Solar Energy Center will require extending the transmission bus at Glint Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Glint Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Glint Substation
(9) Participation with Other Utilities:	None

Schedule 10

Status Report and Specifications of Proposed Transmission Lines

Indrio Solar Energy Center (St. Lucie County)

The Indrio Solar Energy Center will require bifurcating the new FPL Sunbreak - Heritage 230 kV transmission line approximately 0.0 miles to connect a new Estuary substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Heritage 230 kV transmission line to new Estuary Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Estuary Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Middle Lake Solar Energy Center (Madison County)

The Middle Lake Solar Energy Center will require extending the transmission bus at future Bandit Substation approximately 0.0 miles to connect a new Sound substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Bandit Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	161 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Sound Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Ambersweet Solar Energy Center (Indian River County)

The Indrio Solar Energy Center will require bifurcating the new FPL Sunbreak - Kiran 230 kV transmission line approximately 0.0 miles to connect a new Ambersweet substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Sunbreak - Kiran 230 kV transmission line to new Ambersweet Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ambersweet Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

County Line Solar Energy Center (DeSoto County)

The County Line Solar Energy Center will require extending the transmission bus at Notts Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Notts Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Notts Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Saddle Solar Energy Center (DeSoto County)

The Saddle Solar Energy Center will require extending the transmission bus at Ponna Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Ponna Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ponna Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Cocoplum Solar Energy Center (Hendry County)

The Cocoplum Solar Energy Center will require extending the transmission bus at Witt Substation approximately 0.0 miles to connect a new Mulberry substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Witt Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Mulberry Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Catfish Solar Energy Center (Okeechobee County)

The Catfish Solar Energy Center will require extending the transmission bus at Pyrite Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Pyrite Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Pyrite Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Hardwood Hammock Solar Energy Center (Walton County)

The Hardwood Hammock Solar Energy Center will require extending the transmission bus at Quail Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Quail Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Quail Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Maple Trail Solar Energy Center (Baker County)

The Maple Trail Solar Energy Center will require extending the transmission bus at Deodar Substation approximately 0.0 miles to connect a new Maple substation and connect the solar PV inverter array.

(1) Point of Origin and Termination:	Deodar Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Maple Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Pinecone Solar Energy Center (Calhoun County)

The Pinecone Solar Energy Center will require extending the transmission bus at Chinkapin Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Chinkapin Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Chinkapin Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Joshua Creek Solar Energy Center (DeSoto County)

The Joshua Creek Solar Energy Center will require extending a transmission bus at Stallion Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Stallion Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Stallion Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Spanish Moss Solar Energy Center (St. Lucie County)

The Spanish Moss Solar Energy Center will require extending the transmission bus at Apricot Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Apricot Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Apricot Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Vernia Solar Energy Center (Indian River County)

The Vernia Solar Energy Center will require extending the transmission bus at Ambersweet Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Ambersweet Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Ambersweet Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

LaBelle Solar Energy Center (Hendry County)

The Labelle Solar Energy Center will require extending the transmission bus at Swamp Substation approximately 0.0 miles to connect the solar PV inverter array.

(1) Point of Origin and Termination:	Swamp Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2027 End date: 2028
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Swamp Substation
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Lansing Smith Battery Energy Storage System Center (Bay County)

The Lansing Smith Battery Energy Storage System Center will require extending the transmission bus at Lansing Smith Switchyard approximately 0.26 miles to connect the BESS.

(1) Point of Origin and Termination:	Lansing Smith Switchyard
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.26 miles
(5) Voltage:	230 kV
(6) Anticipated Construction Timing:	Start date: 2025 End date: 2026
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Lansing Smith Switchyard
(9) Participation with Other Utilities:	None

Schedule 10
Status Report and Specifications of Proposed Transmission Lines

Putnam Battery Energy Storage System Center (Putnam County)

The Putnam Battery Energy Storage System Center will require extending the transmission bus at Putnam Substation approximately 0.3 miles to connect the BESS.

(1) Point of Origin and Termination:	Putnam BESS U1 Substation
(2) Number of Lines:	1
(3) Right-of-way	FPL – Owned
(4) Line Length:	0.3 miles
(5) Voltage:	115 kV
(6) Anticipated Construction Timing:	Start date: 2026 End date: 2027
(7) Anticipated Capital Investment: (Trans. and Sub.)	Included in total installed cost on Schedule 9
(8) Substations:	Putnam BESS U1Substation
(9) Participation with Other Utilities:	None

Schedule 11.1: FPL

Existing Firm and Non-Firm Capacity and Energy by Primary Fuel Type
Actuals for the Year 2024

	(1)	(2)	(3)	(4)	(5)	(8)	(9)
		Net (MW) Capability				**NEL**	**Fuel Mix**
	Generation by Primary Fuel	**Summer (MW)**	**Summer (%)**	**Winter (MW)**	**Winter (%)**	**GWh [2]**	**%**
(1)	Coal	215	0.6%	215	0.6%	533	0.4%
(2)	Nuclear	3,502	9.8%	3,588	9.7%	28,009	19.2%
(3)	Residual	0	0.0%	0	0.0%	0	0.0%
(4)	Distillate	134	0.4%	163	0.4%	116	0.1%
(5)	Natural Gas	24,170	67.8%	25,345	68.6%	104,335	71.4%
(6)	Landfill Gas	3	0.0%	3	0.0%		
(7)	Solar (Firm & Non-Firm)	7,038	19.7%	7,038	19.1%	12,404	8.5%
(8)	Battery	469	1.3%	469	1.3%	-	-
(9)	***FPL Existing Units Total [1]:***	***35,531***	**99.7%**	***36,821***	**99.7%**	***145,398***	***99.5%***
(10)	Renewables (Purchases)- Firm	122	0.3%	109	0.3%	1,855	1.3%
(11)	Renewables (Purchases)- Non-Firm	Not Applicable	---	Not Applicable	---	1,162	0.8%
(12)	***Renewable Total:***	**122**	**0.0**	**109**	**0.0**	**3,017**	**2.1%**
(13)	***Purchases Other / (Sales) :***	**0.0**	**0.0%**	**0.0**	**0.0%**	**(2,312)**	**-1.6%**
(14)	***Total:***	***35,653***	***100.0%***	***36,930***	***100.0%***	***146,103***	***100.0%***

Note:

(1) FPL Existing Units Total values on row (9), columns (2) and (4) match the Total Nameplate System Generating Capacity values found on Schedule 1 for Summer and Winter.

(2) Net Energy for Load GWh values on row (14), column (8), matches Schedule 6.1 value for 2024.

(3) Information on projected renewable capacity and energy is available in Schedule 6.1, Schedule 8, and Schedule 9.

Schedule 11.2: FPL

Existing Non-Firm Self-Service Renewable Generation Facilities
Actuals for the Year 2024 1/

(1)	(2)	(3)	(4)	(5)	(6) = (3)+(4)-(5)
Type of Facility	Installed Capacity DC (MW)	Renewable Projected Annual Output (MWh) 2/	Annual Energy Purchased from FPL (MWh) 3/	Annual Energy Sold to FPL - Total (MWh) 4/	Projected Annual Energy Used by Customers 5/
Customer-Owned Renewable Generation (0 kW to 10 kW)	733.80	1,063,276	1,072,792	484,470	1,651,598
Customer-Owned Renewable Generation (> 10 kW to 100 kW)	484.07	774,996	701,611	266,711	1,209,896
Customer-Owned Renewable Generation (> 100 kW - 2 MW)	66.30	110,257	393,691	19,200	484,748
Totals	1,284.17	1,948,529	2,168,094	770,381	3,346,242

1/ There were approximately 113,097 customers with renewable generation facilities interconnected with FPL on December 31, 2024.

2/ The Projected Annual Output value is based on NREL's PV Watts 1 program and uses the Installed Capacity value in column (2), adjusted for the date when each facility was installed and assuming each facility operated as planned.

3/ The Annual Energy Purchased from FPL is an actual value from FPL's metered data for 2024.

4/ The Annual Energy Sold to FPL - Total is an actual value from FPL's metered data for 2024. These are the total MWh that were "overproduced" by the customer each month throughout 2024.

5/ The Projected Annual Energy Used by Customers is a projected value that equals:
(Renewable Projected Annual output + Annual Energy Purchased) minus the Annual Energy Sold to FPL - Total).

Schedule 11.3: FPL

Renewable Capacity and Energy Projections, 2025-2034

Capacity Projections (Nameplate MW)

Renewable Type:	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Solar (Firm & Non-Firm)	7,932	8,826	10,018	11,508	13,296	15,531	17,766	20,001	22,236	24,471
Renewables (Purchases)- Firm	420	420	417	417	417	417	417	362	272	272
Renewables (Purchases)- Non-Firm	120	120	120	120	120	120	120	120	120	120
Customer-Owned Renewable Generation	1,275	1,616	2,013	2,465	2,963	3,528	4,140	4,720	5,350	6,027

Energy Projections (GWh)

Renewable Type:	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Solar (Firm & Non-Firm)	17,692	19,662	21,736	25,140	29,159	34,294	39,720	45,254	50,328	55,800
Renewables (Purchases)- Firm	1,855	1,855	1,855	1,855	1,855	1,855	1,855	1,855	1,855	1,855
Renewables (Purchases)- Non-Firm	*	*	*	*	*	*	*	*	*	*
Customer-Owned Renewable Generation	2,056	2,633	3,298	4,060	4,909	5,860	6,908	7,960	9,027	10,178

* FPL does not project non-firm energy as it is dependent on outside factors. Energy production from FPL's 120 MW of solar PPAs is included in the "Solar" entry

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CHAPTER IV

Environmental and Land Use Information

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IV. Environmental and Land Use Information

IV.A. Protection of the Environment

Reliable and low-cost energy is the lifeblood of Florida's growing population, expanding economy, and environmental resource restoration and management. Through its commitment to environmental excellence, FPL is helping to solve Florida's energy challenges sustainably and responsibly, while maintaining service reliability and keeping customer rates as low as possible. With one of the cleanest, most efficient power-generation fleets in the nation, FPL has reduced its use of heavy oil, including foreign oil, by approximately 99.99 percent – from approximately 41 million barrels annually in 2001 to less than 0.181 million barrels in 2024. FPL also has one of the lowest emissions profiles among U.S. utilities. In 2024, CO_2 rates for FPL were 18% lower, then the U.S. electric power sector average. At the end of 2024, FPL had approximately 7,038 MW of solar generation capability on its system (which consists entirely of universal solar PV), making FPL the largest producer of solar energy-generated electricity in Florida. In addition, FPL also has renewable energy purchase agreements for approximately 120 MW of universal solar PV generation.

This 2025 Site Plan for FPL presents a resource plan which shows a significant amount of additional solar. FPL's system is projected to have approximately 24,471 MW of solar by the end of the ten-year reporting period (2034) for this Site Plan.

FPL maintains its commitment to environmental stewardship through proactive collaboration with communities and organizations working to preserve Florida's unique habitat and natural resources. The many projects and programs in which FPL actively participates includes the creation and management of the Manatee Lagoon – An FPL Eco-Discovery Center®, a busy and thriving center in its nine years of operation which welcomes close to 200,000 visitors annually. In addition, the Everglades Mitigation Bank, Solar Stewardship program and the Turkey Point Crocodile Management Program are excellent examples of FPL's stewardship. Over the past 18 years, FPL has invested more than $160 million to construct and retrofit more than 185,000 poles to make them more bird-friendly, reducing avian risk and improving service reliability to our customers. To identify and proactively address high-risk distribution structures, FPL created the energy industry's first avian risk assessment model. In 2022, FPL updated the avian risk assessment model as part of integrating Gulf Power into FPL's Avian Protection Program, and to further enhance avian assessment for eagles and wood storks, and protection processes.

In 2017, FPL launched its Solar Stewardship program in partnership with Audubon Florida. For the majority of its solar sites, FPL works with Audubon Florida and other local organizations to craft site-specific habitat enhancement and preservation plans focused on providing habitat opportunities for birds, pollinators and other wildlife. FPL accomplishes this through a variety of prescriptive methodologies, including but not limited to:

- Restoring hydrology to wetlands;
- Increasing biodiversity through the use of appropriate native plant species;
- Removing invasive species and implementing procedures to prevent regrowth;
- Incorporating pollinator species into ground covers; and
- Installing artificial perches, nest boxes and platforms for wildlife use.

FPL continues to work with regulatory agencies, municipalities, academic institutions, and community groups to address local or regional environmental objectives.

IV.B Environmental Organization Contributions

In 2024, FPL, through its charitable arm, the NextEra Energy Foundation, supported a broad base of environmental organizations with donations focused on education, conservation, and research. Those organizations include Fish & Wildlife Foundation of Florida, Florida State Parks Foundation, Inwater Research Group, Florida Defenders of Wildlife, Mote Marine Laboratory and Aquarium, Ocean Research & Conservation Association, Navarre Beach Sea Turtle Conservation Center, Conservation Florida, East Coast Zoological Foundation, Gulfarium C.A.R.E. Foundation, North Florida Land Trust, and Audubon (state & local chapters). FPL employees serve in board and leadership positions for many organizations that focus on environmental restoration, preservation, and stewardship. A partial list of these organizations includes Grassy Waters Conservancy, Loggerhead Marinelife Center, Marine Resources Council, Busch Wildlife Sanctuary, Florida Oceanographic Society and Audubon Florida. FPL employees also invest volunteer hours supporting conservation partners in maintaining, restoring, and protecting waters, wetlands, forests, beaches, parks, historic sites, and wildlife.

IV.C Environmental Communication and Facilitation

FPL is involved in many efforts to enhance environmental conservation through the facilitation of energy efficiency, environmental awareness, and through public education. Some of FPL's 2024 environmental outreach activities are summarized in Table IV.C.1.

Table IV.C.1: 2024 FPL Environmental Outreach Activities

Activity	Count (#)
Visitors to Manatee Lagoon - An FPL Eco-Discovery Center®	**197,289**
Number of website visits to Manatee Lagoon website, visitmanateelagoon.com	856,798 781,808
Number of website visits to NextEra and FPL's Environmental & Corporate Sustainability Websites	**22,099**
Visitors to Manatee Park, Ft. Myers	**191,805**
Home Energy Surveys	Field Surveys: 16,452 Phone Surveys: 9,603 Online Surveys: 74,124 **Total: 100,179**

IV.D Environmental Policy

FPL and its parent company, NextEra Energy, are committed to remaining an industry leader in environmental conservation and stewardship, not only because it makes business sense, but because it is the right thing to do. This commitment to compliance, conservation, communication, and continuous improvement fosters a culture of environmental excellence and drives its business planning, operations, and daily work.

In accordance with commitments to environmental compliance, conservation and stewardship, FPL and NextEra Energy endeavor to:

Comply:

- Site, design, permit, construct, operate, and maintain our facilities in an environmentally responsible manner;
- Comply with all applicable environmental laws, regulations, and permits;
- Proactively identify environmental risks and take action to mitigate those risks;
- Participate in legislative and regulatory processes to ensure that environmental laws, regulations, guidance documents, and policies are technically sound and economically feasible; and
- Pursue opportunities to exceed environmental standards.

Conserve:

- Promote the efficient use of energy, both within our company and in our communities;

- Prevent pollution, minimize waste, and conserve natural resources;
- Promote sustainability in our daily actions and project planning, where applicable;
- Endeavor to avoid, to the extent practicable, impacts to habitat, wildlife, jurisdictional waters, and cultural resources; minimize, and/or mitigate unavoidable impacts to such resources; and
- Lead with innovative solutions that synthesize environmental conservation and prudent operations.

<u>Communicate:</u>

- Communicate this policy annually to all employees, and maintain on internal website for easy reference;
- Invest in environmental training and awareness to achieve a corporate culture of environmental excellence;
- Maintain honest and open dialogue with stakeholders, including federal, state and local agencies on environmental goals, processes, and performance; and
- Highlight policy with external stakeholders and provide accurate reporting on environmental impacts (sustainability reporting).

<u>Continuously Improve:</u>

- Establish, monitor, and report progress toward environmental targets;
- Review and update this policy on a regular basis;
- Drive continuous improvement through ongoing evaluations of our environmental management system to incorporate lessons learned and best practices;
- Perform self-assessments of our operating facilities through the internal environmental audit program to ensure compliance, share best practices, and incorporate learnings across the fleet; and
- Maintain strong strategic vision to continuously seek innovative win-win solutions to complex environmental issues

FPL complies with all environmental laws, regulations, and permit requirements, and designs, constructs, and operates its facilities in an environmentally sound and responsible manner. FPL also responds immediately and effectively to any known environmental hazards or non-compliance situations. The commitment to the environment does not end there. FPL proactively pursues opportunities to perform better than current environmental standards require, including reducing waste and emission of pollutants, recycling materials, and conserving natural resources throughout their operations and day-to-day work activities. FPL encourages cost-effective, efficient uses of energy, both within the Company and with its customers. These actions are just a few examples of how FPL is committed to the environment.

To ensure FPL is adhering to its environmental commitment, it has developed rigorous environmental governance procedures and programs. These include its Environmental Assurance Program. Through this program, FPL conducts periodic environmental self-evaluations to verify that its operations comply with environmental laws, regulations, and permit requirements. Regular evaluations also help identify best practices and opportunities for improvement.

IV.E Environmental Management

To successfully implement this Environmental Policy, FPL has developed a robust Environmental Management System to direct and control the fulfillment of the organization's environmental responsibilities. A key component of the system is an Environmental Assurance Program, which is described in section IV.F below. Other system components include: executive management support and commitment, dedicated environmental corporate governance program, written environmental policies and procedures, delineation of organizational responsibilities and individual accountabilities, allocation of appropriate resources for environmental compliance management (which includes reporting and corrective action when non-compliance occurs), environmental incident and/or emergency response, environmental risk assessment/management, environmental regulatory development and tracking, and environmental management information systems.

IV.F Environmental Assurance Program

FPL's Environmental Assurance Program consists of activities designed to evaluate environmental performance, verify compliance with corporate policy and legal and regulatory requirements, and communicate results to corporate management. The principal mechanism for pursuing environmental assurance is an environmental audit. An environmental audit is defined as a management tool comprised of a systematic, documented, risk-based, and objective evaluation of the performance of the organization and its specific management systems and equipment designed to protect the environment. An environmental audit's primary objective is to facilitate management control of environmental practices and assess compliance with existing environmental regulatory requirements and corporate policies. In addition to FPL facility audits, through the Environmental

Assurance Program, audits of third-party vendors used for recycling and/or disposal of waste generated by FPL operations are performed. Vendor audits provide information used for selecting candidates or incumbent vendors for disposal and recycling needs.

In addition to periodic environmental audits, NextEra Energy's Environmental Construction Compliance Assurance Program provides routine onsite inspections during construction and site-specific environmental training to everyone anticipated to be onsite during construction. Similar to an environmental audit, these inspections are performed to ensure compliance with the requirements of environmental permits, licenses, and corporate policies during the construction phase. Additionally, the Construction Compliance Assurance Program has integrated remote satellite and drone monitoring technology to broaden its inspection capabilities and increase the frequency of onsite observations.

FPL has also implemented a Corporate Environmental Governance System in which quarterly reviews are performed of each business unit deemed to have potential for significant environmental exposure. Quarterly reviews evaluate operations for potential environmental risks and consistency with the Environmental Policy. Items tracked during the quarterly reviews include processes for the identification and management of environmental risks, metrics, and indicators and progress changes since the most recent review.

IV.G Preferred and Potential Sites

Based upon projection of future resource needs and analyses of viable resource options, 39 Preferred Sites and 18 Potential Sites have been identified for adding future generation. Some of these sites currently have existing generation. Preferred Sites are those locations where significant reviews have taken place and action has either been taken, action is committed, or it is likely that action will be taken to site new generation. Potential Sites are those with attributes that would support the siting of generation and are under consideration as a location for future generation. The identification of a Potential Site does not necessarily indicate that a definitive decision has been made to pursue new generation, generation expansion, or modernization, nor does this designation necessarily indicate that the size or technology of a generating resource has been determined. The Preferred Sites and Potential Sites are discussed in separate sections below.

IV.G.1 Preferred Sites

For the 2025 Ten-Year Site Plan, 39 Preferred Sites have been identified. These include new sites for the development of solar generation facilities, battery storage facilities, and nuclear generation. Sites for numerous solar additions in 2026 and 2027 have been selected, and these sites are described in this section. Potential sites for possible 2028 and beyond solar additions are discussed later in the Potential Site section.

These 39 Preferred Sites are listed in Table IV.G.1 below, and information about each site is presented in the Appendix at the end of this document. The sites are presented in general chronological order of when resources are projected to be added to the FPL system. The topographical features of each site, land use, and facility layout figures are provided in maps that also appear in the Appendix at the end of this document. Note that the first several Preferred Sites listed do not show up in the Appendix section of this document as they are Battery Energy Storage System Centers that are all located at existing solar sites. These sites are also referred to as the 521.5 MW "2025 Gulf Battery" throughout this document.

Table IV.G.1: List of FPL Preferred Sites

Site Name	County	Technology
Canoe Battery Energy Storage System Center	Okaloosa	Storage
Blackwater Battery Energy Storage System Center	Santa Rosa	Storage
Chipola River Battery Energy Storage System Center	Calhoun	Storage
Fourmile Creek Battery Energy Storage System Center	Calhoun	Storage
Tenmile Creek Battery Energy Storage System Center	Calhoun	Storage
Shirer Branch Battery Energy Storage System Center	Calhoun	Storage
Kayak Battery Energy Storage System Center	Okaloosa	Storage
Flatford Solar Energy Center	Manatee	Solar
Mare Branch Solar Energy Center	DeSoto	Solar
Price Creek Solar Energy Center	Columbia	Solar
Swamp Cabbage Solar Energy Center	Hendry	Solar
Big Brook Solar Energy Center	Calhoun	Solar
Mallard Solar Energy Center	Brevard	Solar
Boardwalk Solar Energy Center	Collier	Solar
Goldenrod Solar Energy Center	Collier	Solar
North Orange Solar Energy Center	St. Lucie	Solar
Sea Grape Solar Energy Center	St. Lucie	Solar
Clover Solar Energy Center	St. Lucie	Solar
Sand Pine Solar Energy Center	Calhoun	Solar
Hendry Solar Energy Center	Hendry	Solar
Tangelo Solar Energy Center	Okeechobee	Solar
Wood Stork Solar Energy Center	St. Lucie	Solar
Indrio Solar Energy Center	St. Lucie	Solar
Middle Lake Solar Energy Center	Madison	Solar
Ambersweet Solar Energy Center	Indian River	Solar
County Line Solar Energy Center	Charlotte, DeSoto	Solar
Saddle Solar Energy Center	DeSoto	Solar
Cocoplum Solar Energy Center	Hendry	Solar
Catfish Solar Energy Center	Okeechobee	Solar
Hardwood Hammock Solar Energy Center	Walton	Solar
Maple Trail Solar Energy Center	Baker	Solar
Pinecone Solar Energy Center	Calhoun	Solar
Joshua Creek Solar Energy Center	DeSoto	Solar
Spanish Moss Solar Energy Center	St. Lucie	Solar
Vernia Solar Energy Center	Indian River	Solar
LaBelle Solar Energy Center	Hendry	Solar
Lansing Smith Battery Energy Storage System Center	Bay	Storage
Putnam Battery Energy Storage System Center	Putnam	Storage
Turkey Point 6 & 7	Miami-Dade	Nuclear

IV.G.2 Potential Sites

There are 18 Potential Sites currently identified for future generation and storage additions to meet projected capacity and energy needs. Each of these Potential Sites offers a range of considerations relative to engineering and/or costs associated with the construction and operation of feasible technologies. In addition, each Potential Site has distinctive characteristics that would require further definition and attention. Unless otherwise noted, the water quantities discussed below are in reference to universal solar PV generation rather than for gas-fueled generation.

Permits are considered obtainable for each site. No significant environmental constraints are currently known for any of these sites. FPL considers each site equally viable. These Potential Sites are listed in Table IV.G.2 below and are briefly discussed in the Appendix at the end of this document.

Table IV.G.2: List of FPL Potential Sites

Name	County	Technology
Waveland Solar Energy Center	St. Lucie	Solar
Inlet Solar Energy Center	Indian River	Solar
Wabasso Solar Energy Center	Indian River	Solar
Shores Solar Energy Center	Indian River	Solar
Beachland Solar Energy Center	Indian River	Solar
Treefrog Solar Energy Center	Collier	Solar
Honeybee Solar Energy Center	Collier	Solar
Bromeliad Solar Energy Center	Collier	Solar
Myakka Solar Energy Center	Manatee	Solar
Sand Gully Solar Energy Center	DeSoto	Solar
Gum Creek Solar Energy Center	Jackson	Solar
Cardinal Solar Energy Center	Indian River	Solar
Pine Lily Solar Energy Center	St. Lucie	Solar
Wild Lime Solar Energy Center	St. Lucie	Solar
Spoonbill Solar Energy Center	Collier	Solar
Shell Creek Solar Energy Center	Charlotte, DeSoto	Solar
Carlton Solar Energy Center	St. Lucie	Solar
Owen Branch Solar Energy Center	Manatee	Solar

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CHAPTER V

Other Planning Assumptions & Information

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Introduction

The FPSC, in Docket No. 960111-EU, specified certain information to be included in an electric utility's Ten-Year Power Plant Site Plan filing. This specified information includes 12 items listed under a heading entitled "Other Planning Assumptions and Information." These 12 items concern specific aspects of a utility's resource planning work. The FPSC requested a discussion or a description of each of these items.

These 12 items are addressed individually below as separate "Discussion Items".

Discussion Item # 1: Describe how any transmission constraints were modeled and explain the impacts on the plan. Discuss any plans for alleviating any transmission constraints.

FPL's resource planning work considers two types of transmission limitations/constraints: external limitations and internal limitations. External limitations involve FPL's ties to its neighboring electric systems. Internal limitations involve the flow of electricity within the FPL system.

The external limitations are important because they affect the development of assumptions for the amount of external assistance that is available to the FPL area, as well as the amount and price of economy energy purchases. Therefore, these external limitations are incorporated both in the reliability analysis and economic analysis aspects of resource planning. The amount of external assistance that is assumed to be available is based on the projected transfer capability to the FPL area from outside entities as well as historical levels of available assistance. In the LOLP portion of its reliability analyses, FPL's resource planning group models the amount of external assistance as an additional generator(s) within the system that provides capacity in all but the peak load months. The assumed amount and price of economy energy are based on historical values and projections from production costing models.

Internal transmission limitations are addressed in economic analyses by identifying potential geographic locations for potential new generating units that minimize adverse impacts to the flow of electricity within the system. The internal transmission limitations are also addressed by: 1) developing the direct costs for siting potential new units at different locations, 2) evaluating the cost impacts created by the new unit/unit location combination on the operation of existing generating units in the system, and/or 3) evaluating the costs of transmission and/or generation additions that may be needed to address regional concerns regarding an imbalance between load and generation in a given region. Costs for these site, region, and system factors are developed for use in economic analyses. These factors are also considered in both system and regional reliability analyses. When analyzing DSM portfolios, such as for a DSM Goals docket, the potential to avoid or defer regional transmission additions that might otherwise be needed is typically analyzed. In addition, transfer limits for capacity and energy that can be imported into the Southeastern Florida region of FPL's area (Miami-Dade and Broward Counties) or transferred between FPL and FPL NWFL service areas are also developed, as applicable, for use in reliability analyses and production costing analyses.

Annual transmission planning work determines transmission additions needed to address limitations and maintain/enhance system and regional reliability. Planned transmission facilities to interconnect and integrate generating units in the resource plan, including those transmission facilities that must be certified under the Transmission Line Siting Act, are presented in Chapter III.

Discussion Item # 2: Discuss the extent to which the overall economics of the plan were analyzed. Discuss how the plan is determined to be cost-effective. Discuss any changes in the generation expansion plan as a result of sensitivity tests to the base case load forecast.

FPL's resource planning group typically performs economic analyses of competing resource plans using levelized system average electric rates (*i.e.*, a Rate Impact Measure or RIM approach) as an economic criterion. In addition, for analyses in which DSM levels are not changed and only supply options are analyzed, the equivalent criterion of the cumulative present value of revenue requirements (CPVRR) may also be used.[7] This type of evaluation was used in developing the resource plan for the 2025 Site Plan.

Discussion Item # 3: Explain and discuss the assumptions used to derive the base case fuel forecast. Explain the extent to which the utility tested the sensitivity of the base case plan to high and low fuel price scenarios. If high and low fuel price sensitivities were performed, explain the changes made to the base case fuel price forecast to generate the sensitivities. If high and low fuel price scenarios were performed as part of the planning process, discuss the resulting changes, if any, in the generation expansion plan under the high and low fuel price scenarios. If high and low fuel price sensitivities were not evaluated, describe how the base case plan is tested for sensitivity to varying fuel prices.

[7] FPL's basic approach in its resource planning work is to base decisions on a lowest electric rate basis. However, when DSM levels are considered a "given" in the analysis (*i.e.*, when only new generating options are considered), the lowest electric rate basis approach and the lowest system cumulative present value of revenue requirements (CPVRR) basis approach yield identical results in terms of which resource options are more economic. In such cases, resource options can be evaluated on the simpler-to-calculate (but equivalent) lowest CPVRR basis.

The basic assumptions used to derive fuel price forecasts are discussed in Chapter III of this document. FPL's resource planning group may use a single fuel cost forecast, or multiple fuel cost forecasts (Low, Medium, and High), in its analyses as appropriate.

In cases where multiple fuel cost forecasts are used, a Medium fuel cost forecast is developed first. Then the approach has been to adjust the Medium fuel cost forecast upward (for the High fuel cost forecast) or downward (for the Low fuel cost forecast) by multiplying the annual cost values from the Medium fuel cost forecast by a factor of (1 + the historical volatility of the 12-month forward price, one year ahead) for the High fuel cost forecast, or by a factor of (1 – the historical volatility of the 12-month forward price, one year ahead) for the Low fuel cost forecast.

The resource plan presented in this Site Plan is based on an updated fuel cost forecast developed in September 2024.

Discussion Item # 4: Describe how the sensitivity of the plan was tested with respect to holding the differential between oil/gas and coal constant over the planning horizon.

In its 2024 and early 2025 resource planning work, a forecast scenario in which the differential between oil/gas and coal was held constant was not utilized. This is, in part, because FPL is currently using small amounts of oil as a fuel and is projecting to use very little coal as a fuel during the ten-year period. These trends are shown on Schedules 5, 6.1, and 6.2 in Chapter III.

Discussion Item # 5: Describe how generating unit performance was modeled in the planning process.

The performance of existing generating units is modeled using current projections for scheduled outages, unplanned outages, capacity output ratings, and heat rate information. Schedule 1 in Chapter I and Schedule 8 in Chapter III present the current and projected capacity output ratings of the existing generating units. The values used for outages and heat rates are generally consistent with the values that have been used in planning studies in recent years.

For new unit performance, FPL utilized current projections for the capital costs, fixed and variable operating and maintenance costs, capital replacement costs, construction schedules, heat rates (as appropriate), and capacity ratings for all construction options in its resource planning work. A summary of this information for the new capacity options that FPL currently projects to add over the reporting horizon for this document is presented on the Schedule 9 forms in Chapter III.

Discussion Item # 6: Describe and discuss the financial assumptions used in the planning process. Discuss how the sensitivity of the plan was tested with respect to varying financial assumptions.

The financial assumptions used in the resource planning analyses that led to the resource plan that is presented in this 2025 Site Plan were: in late 2024, an incremental capital structure of 40.40% debt and 59.60% equity; (ii) a 5.30% cost of debt; (iii) a 10.80% return on equity; and (iv) an after-tax discount rate of 8.04%. In early 2025, these assumptions were changed to: an incremental capital structure of 40.40% debt and 59.60% equity; (ii) a 5.68% cost of debt; (iii) a 10.80% return on equity; and (iv) an after-tax discount rate of 8.15%. No other financial assumptions were used in the 2024 and early 2025 resource planning work.

Discussion Item # 7: Describe in detail the electric utility's Integrated Resource Planning process. Discuss whether the optimization was based on revenue requirements, rates, or total resource cost.

FPL's IRP process is described in detail in Chapter III of this document.

The standard basis for comparing the economics of competing resource plans in FPL's basic IRP process is the impact of the plans on electricity rate levels, with the objective generally being to minimize the projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or RIM approach). As discussed in response to Discussion Item # 2, both the electricity rate perspective and the CPVRR perspective for the system yield identical results in terms of which resource options are more economical when DSM levels are unchanged between competing resource plans. Therefore, in planning work in which DSM levels were unchanged, FPL's resource planning group utilizes the equivalent, but simpler-to-calculate CPVRR perspective.

Discussion Item # 8: Define and discuss the electric utility's generation and transmission reliability criteria.

FPL's resource planning group uses three system reliability criteria in its resource planning work that address various resource options including: utility generation, power purchases, and DSM options. One criterion is a minimum 20% Summer and Winter total reserve margin. Another reliability criterion is a maximum of 0.1 days per-year LOLP. The third criterion is a minimum 10% GRM. These three reliability criteria are discussed in Chapter III of this document.

For transmission reliability analysis, transmission planning criteria have been adopted that are consistent with those established by the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Corporation (SERC). The FRCC and SERC have adopted transmission planning criteria that are consistent with the Reliability Standards established by the NERC. The *NERC Reliability Standards* are available on the NERC internet site (http://www.nerc.com/).

In addition, *Facility Interconnection Requirements* (FIR) documents for the FPL system have been developed. The document for FPL is available on FPL's Open Access Same-time Information System (OASIS) website, https://www.oatioasis.com/FPL/index.html, under the "Interconnection Request Information" directory. Furthermore, all new transmission facilities within the FPL service territory that are used to meet FPL load are planned to comply with Extreme Wind Loading Criteria as implemented in FPL Design Guidelines.

FPL's transmission planning group generally limits planned flows on its transmission facilities to no more than 100% of the applicable thermal rating. There may be isolated cases for which it is acceptable to deviate from the general criteria stated below. There are several factors that could influence these criteria, such as the overall number of potential customers that may be impacted, the probability of an outage actually occurring, transmission system performance, and other factors.

The normal and contingency voltage criteria for FPL stations are provided below:

Normal/Contingency...[8]

Voltage Level (kV)	Vmin (p.u.)	Vmax (p.u.)
69, 115, 138	0.95/0.95	1.05/1.07
161	0.95/0.95	1.05/1.10
230	0.95/0.95	1.06/1.07
500	0.95/0.95	1.07/1.10
Turkey Point (*)	1.013/1.013	1.06/1.06
St. Lucie (*)	1.00/1.00	1.06/1.06

(*) Voltage range criteria for FPL's Nuclear Power Plants

[8] Immediately following a contingency, steady-state voltages may deviate from the normal voltage range if there are known automatic or manual operating actions to adjust the voltage to within the contingency voltage range. However, the steady-state voltage must never exceed voltage System Operating Limits (SOLs), which have a lower limit of 0.90pu and a higher limit of 1.10pu for all transmission facilities, excluding nuclear plant switchyards for which the SOLS are equal to the normal/contingency limits.

Discussion Item # 9: Discuss how the electric utility verifies the durability of energy savings for its DSM programs.

FPL periodically revises the projected impacts of its DSM programs on demand and energy consumption. Engineering models, calibrated with current field-metered data, are updated at regular intervals. Participation trends are tracked for all of FPL's DSM programs in order to adjust impacts each year for changes in the mix of efficiency measures being installed by program participants. For its load management programs, FPL conducts periodic tests of its load management equipment to ensure it is functioning correctly. These tests, plus actual load management events, also allow FPL to gauge the MW reduction capabilities of its load management programs on an ongoing basis.

Discussion Item # 10: Discuss how strategic concerns are incorporated in the planning process.

The Executive Summary and Chapter III provide a discussion of a variety of system concerns/issues that influence FPL's resource planning process. Please see those chapters for a discussion of those concerns/issues.

In addition to these system concerns/issues, there are other strategic factors that FPL's resource planning group typically considers when choosing among resource options. These include: (1) technology risk; (2) environmental risk; and (3) site feasibility. The consideration of these factors may include both economic and non-economic aspects. Technology risk is an assessment of the relative maturity of competing technologies. For example, a prototype technology that has not achieved general commercial acceptance has a higher risk than a technology in wide use and, therefore, assuming all else is equal, is less desirable.

Environmental risk is an assessment of the relative environmental acceptability of different generating technologies and their associated environmental impacts on the utility system, including projected environmental compliance costs. Technologies regarded as more acceptable from an environmental perspective for a prospective resource plan are those that minimize environmental impacts for the utility system as a whole through highly efficient fuel use, state-of-the-art environmental controls, and generating technologies that do not utilize fossil fuels (such as nuclear and solar).

Site feasibility assesses a wide range of economic, regulatory, and environmental factors related to successfully developing and operating the specified technology at the site in question. Projects that are more acceptable have sites with fewer barriers to successful development.

All of these factors play a part in resource planning and decision-making, including decisions to construct capacity or purchase power.

Discussion Item # 11: Describe the procurement process the electric utility intends to utilize to acquire the additional supply-side resources identified in the electric utility's ten-year site plan.

As shown in this 2025 Site Plan, the current resource plan reflects the following major supply-side or generation resource additions in FPL's area: CT component upgrades at various existing CCs, addition of new PV facilities, the addition of new battery storage facilities, and potential new CT additions.

CT upgrades are planned to take place at various CC units throughout the FPL area that address Summer and Winter capacity. The original equipment manufacturers (OEM) of the CTs approached FPL regarding the possibility of upgrading these units. Following negotiations with the OEMs and economic analyses that showed upgrading was cost-effective for customers, FPL decided to proceed with the CT upgrades and the supporting balance of plant modifications.

For new solar, battery and gas generation facilities for FPL, the selection of equipment and installation contractors has been, and will continue to be, done via competitive bidding. FPL's Engineering & Construction (E&C) group seek bids from multiple suppliers for major components such as PV panels, inverters, batteries, combustion turbine generators (CT) and step-up transformers. Where possible, volume is leveraged to achieve economies of scale and options are evaluated based on total cost of ownership. Remaining balance-of-system (BOS) material purchases, as well as engineering and construction services, are typically competitively bid out as well to determine the best value.

Discussion Item # 12: Provide the transmission construction and upgrade plans for electric utility system lines that must be certified under the Transmission Line Siting Act (403.52 – 403.536, F. S.) during the planning horizon. Also, provide the rationale for any new or upgraded line.

FPL has identified the need for one new transmission line that require certification under the Transmission Line Siting Act (as shown on Table III.E.1 in Chapter III).

The 230 kV line will connect FPL's Whidden Substation to a new Sweatt 230 kV Substation. A determination of need for the line was filed with the FPSC in April 2022, and a final order certifying the corridor for the project was issued in September 2022. The project is scheduled to be completed by June 2026. The construction of this line and substation is necessary to serve existing and future FPL customers in the west Florida area in and around Okeechobee, Highlands, Desoto, Collier, Lee, Sarasota, and Manatee Counties in a reliable and effective manner.

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Appendix

Preferred and Potential Solar Site Descriptions and Maps

Appendix A

Site Descriptions, Environmental, and Land Use Information: *Supplemental Information*

Relationship of Regional Hydrogeologic Units to Major Stratigraphic Units and Florida Regions

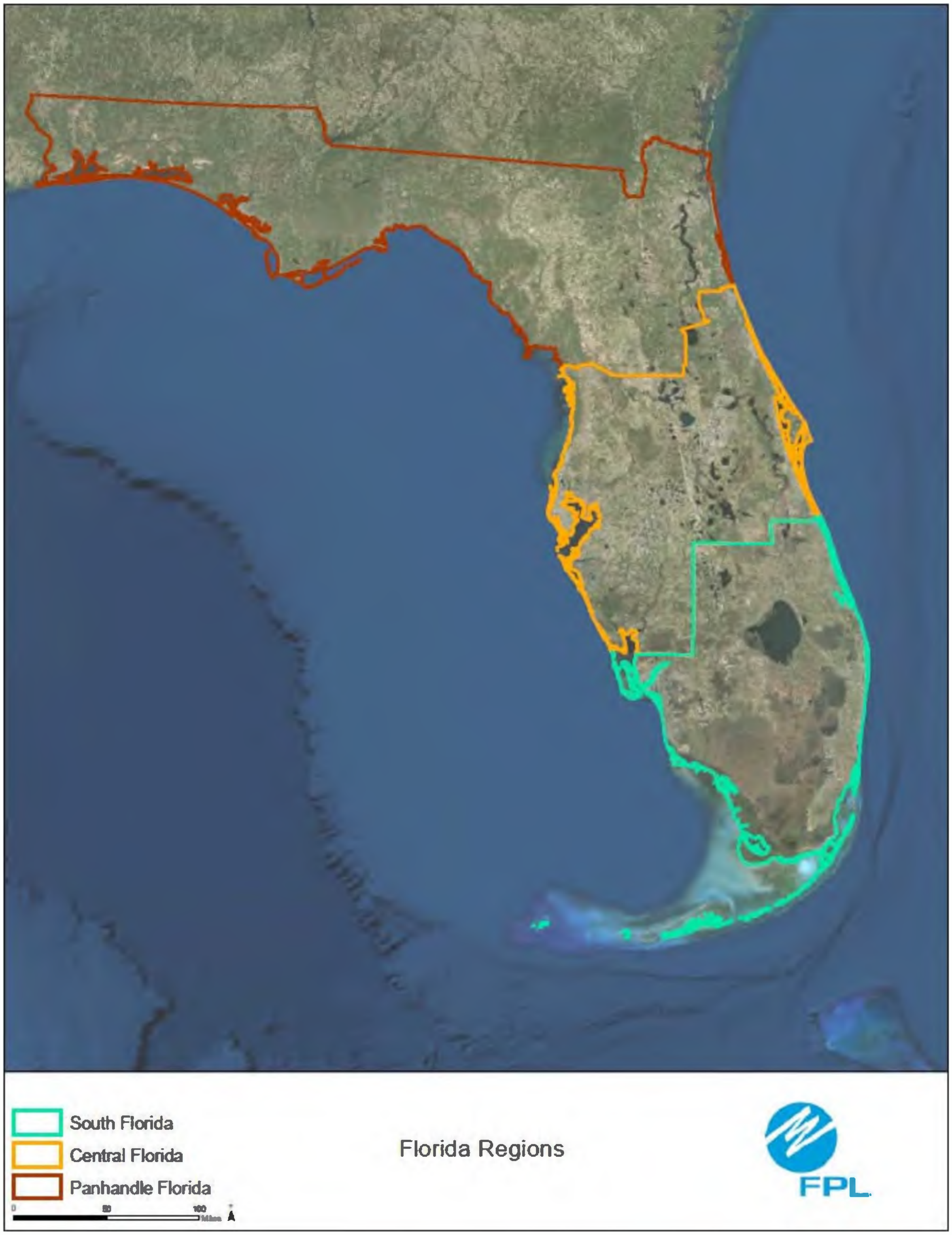
Figure A.A.1: Relationship of Regional Hydrogeologic Units to Major Stratigraphic Units

Relationship of Regional Hydrogeologic Units to Major Stratigraphic Units

		Panhandle Florida		North Florida		South Florida	
System	**Series**	**Stratigraphic Unit**	**Hydrogeologic Unit**	**Stratigraphic Unit**	**Hydrogeologic Unit**	**Stratigraphic Unit**	**Hydrogeologic Unit**
Quaternary	**Holocene**	Undifferentiated terrace marine and fluvial deposits	Surficial aquifer system (Sand and Gravel aquifer)	Undifferentiated terrace marine and fluvial deposits	Surficial aquifer system	Terrace Deposits Miami Limestone Key Largo Limestone Anastasia Formation Fort Thompson Formation Caloosahatchee Marl	Surficial aquifer system (Biscayne aquifer)
	Pleistocene						
Tertiary	**Pilocene**	Citronelle Formation Undifferentiated coarse sand and gravel		Miccosukee Formation Alachua Formation		Tamiami Formation	
	Miocene	Alum Bluff Group Pensacola Clay Intracoastal Formation Hawthorn Group Chipola Formation Bruce Creek Limestone St. Marks Formation Chattahoochee Formation	Intermediate confining unit	Hawthorn Group St. Marks Formation	Intermediate aquifer system or intermediate confining unit	Hawthorn Group	Intermediate aquifer system or intermediate confining unit
	Oligocene	Chickasawhay Limestone Suwannee Limestone Marianna Limestone Bucatunna Clay	Floridan aquifer system	Suwannee Limestone	Floridan aquifer system	Suwannee Limestone	Floridan aquifer system
	Eocene	Ocala Limestone Lisbon Formation Tallahatta Formation Undifferentiated older Rocks		Ocala Limestone Avon Park Formation Oldsmar Formation		Ocala Limestone Avon Park Formation Oldsmar Formation	
	Paleocene	Undifferentiated	Sub-Floridan confining unit	Cedar Keys Formation		Cedar Keys Formation	Sub-Floridan confining unit
Cretaceous and older		Undifferentiated		Undifferentiated	Sub-Floridan confining unit		

Note: This information is referred to in subsection k, Geological Features of Site and Adjacent Areas, for each of the Preferred Sites.

Figure A.A.2: Florida Regions Map



Note: This information is referred to in subsection k, Geological Features of Site and Adjacent Areas, for each of the Preferred Sites

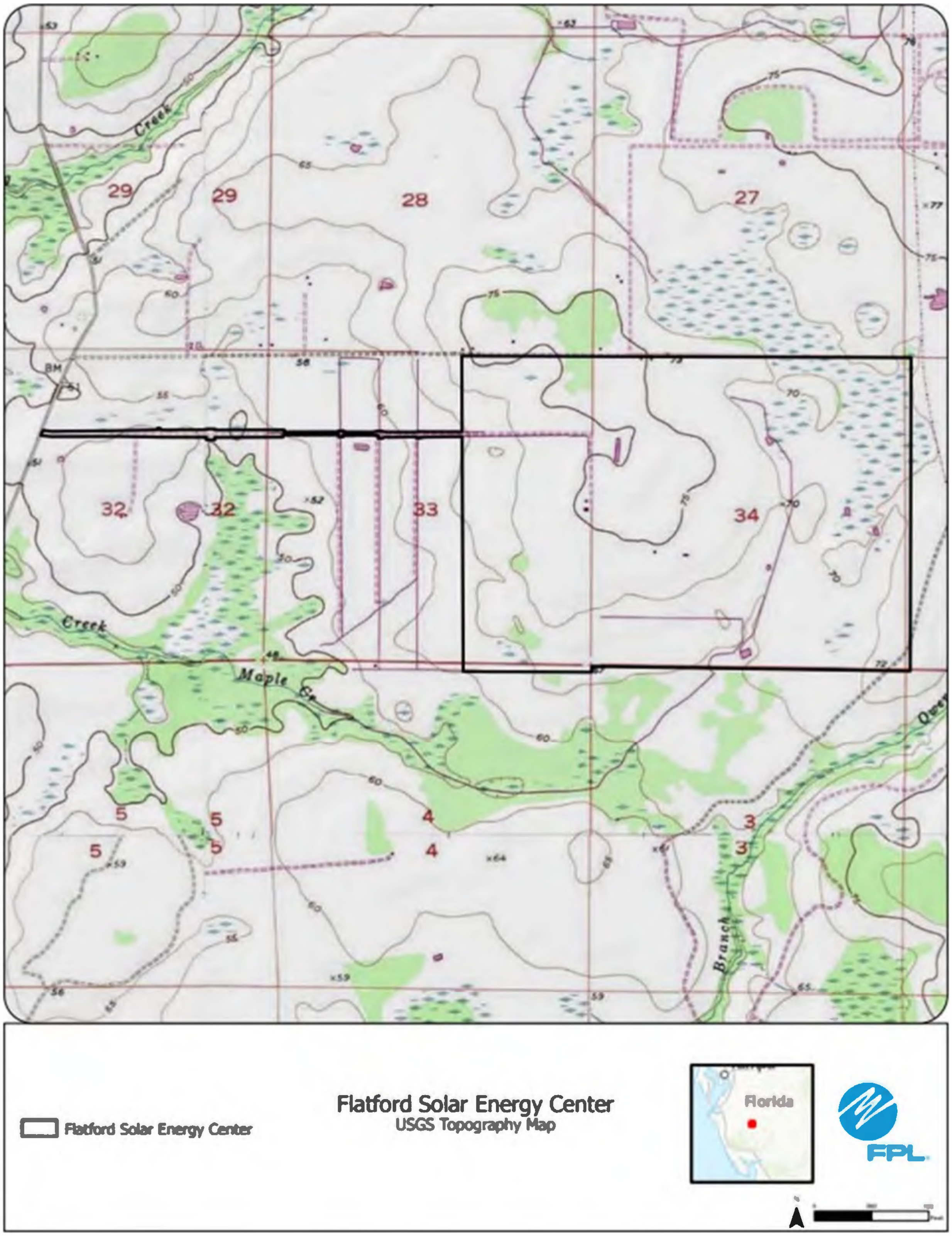
Appendix B Preferred Sites

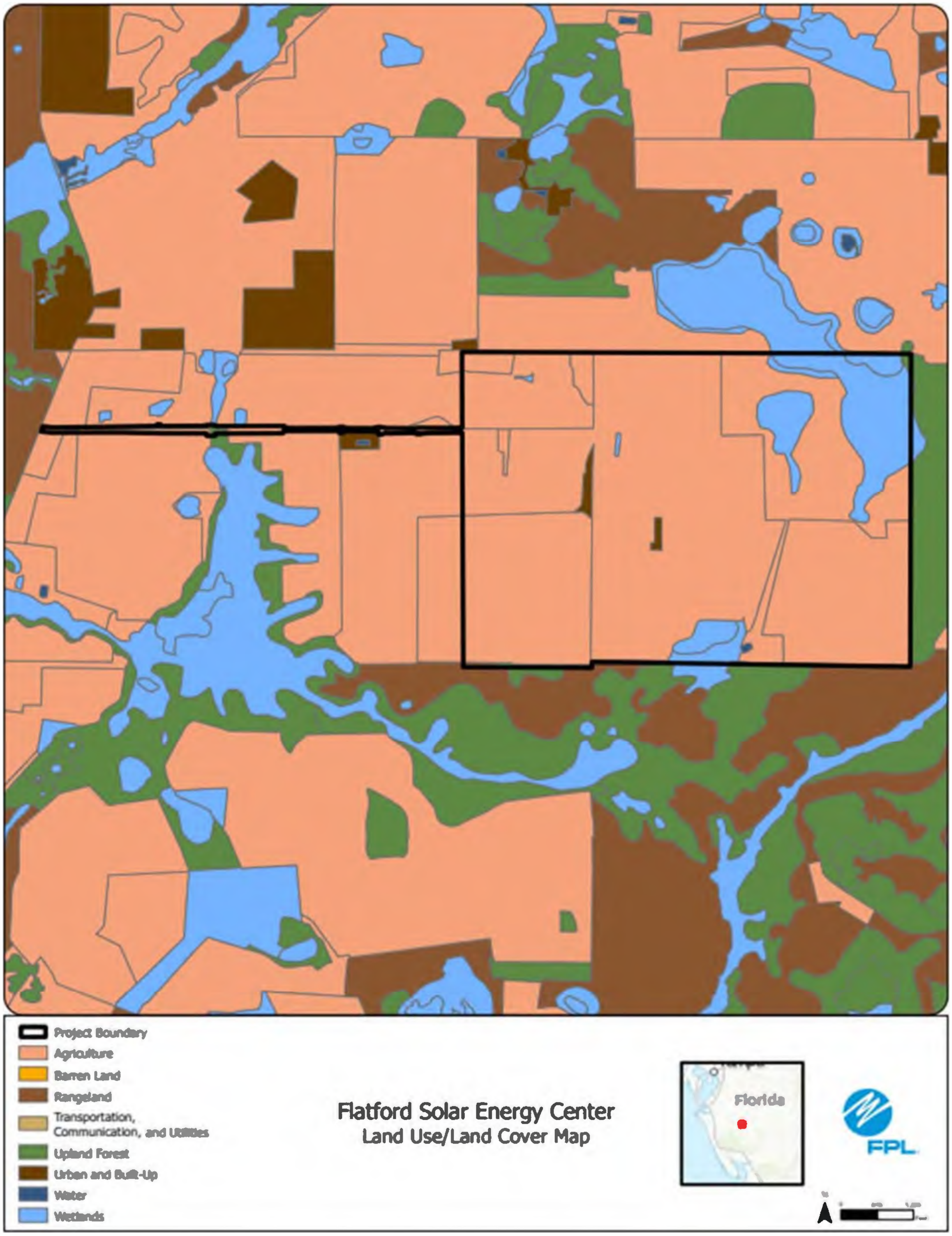
Below are the descriptions regarding each of the 32 Preferred Sites listed in Table IV.G.1. Following the descriptions are maps showing the topographical features, land use, and facility layout of each site.

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #1: Flatford Solar Energy Center, Manatee County

	Preferred Site	Flatford Solar Energy Center
	County	Manatee
	Facility Acreage	925
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Citrus groves and other crop land
	Adjacent Areas	Pasture and other crop lands
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Site is agricultural in nature.
2	Listed Species	Gopher tortoise and Florida sandhill crane
3	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
90	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.)
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s	Status of Applications	FDEP ERP Issued: 12/27/2023 USACE Standard Permit Issued: 01/28/2025


Flatford Solar Energy Center
USGS Topography Map
Flatford Solar Energy Center
Florida
FPL

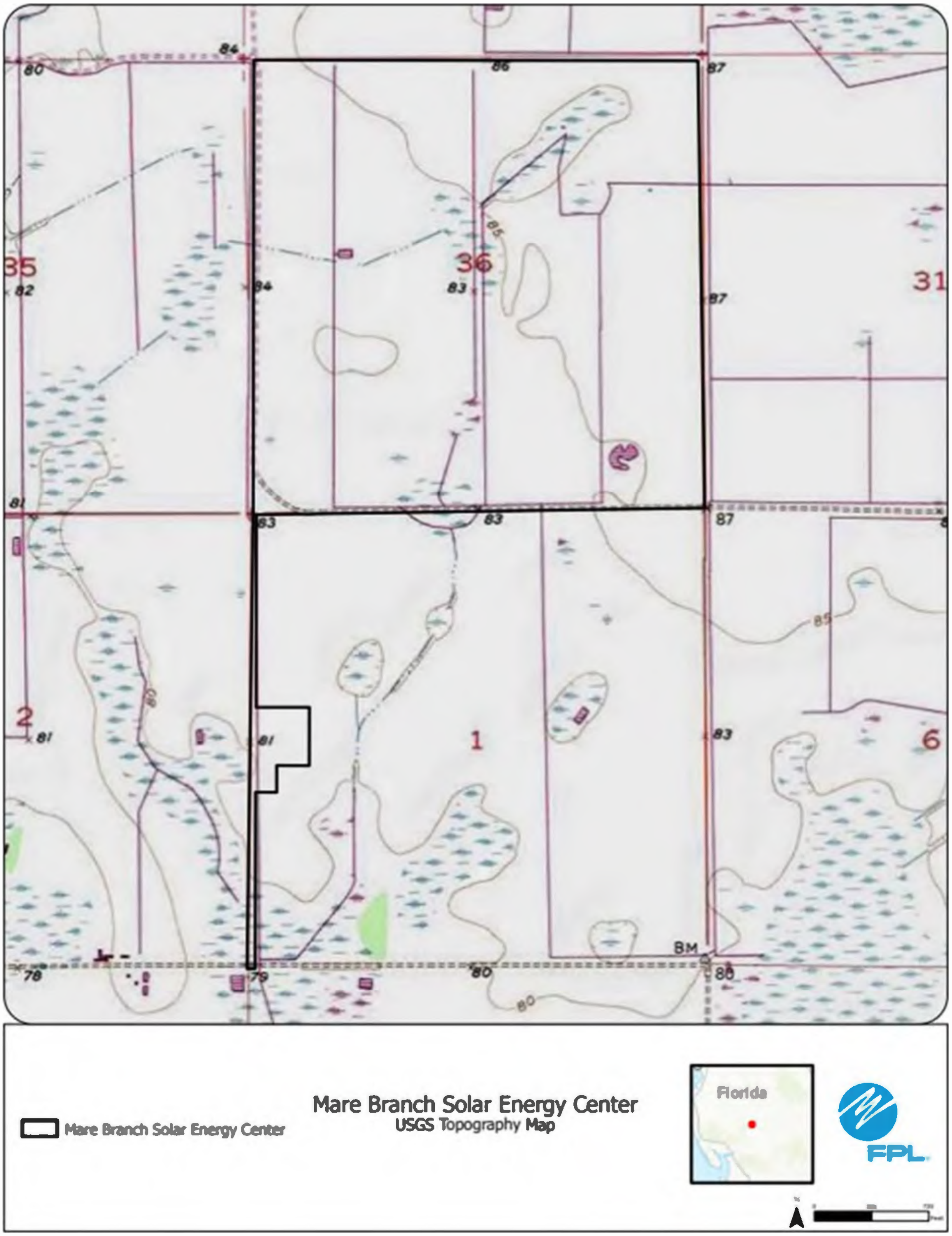

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Flatford Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Flatford Solar Energy Center
Flatford Solar Energy Center
Facility Layout Map
Florida
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #2: Mare Branch Solar Energy Center, DeSoto County

	Preferred Site	Mare Branch Solar Energy Center
	County	DeSoto
	Facility Acreage	669
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Row and field crops
	Adjacent Areas	Solar sites, other row/field crops
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site is primarily row and field crops
2.	Listed Species	Gopher tortoise, Audubon's crested caracara, Florida sandhill crane
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the South region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 8/4/2023 FDEP 404 GP Issued: 8/4/2023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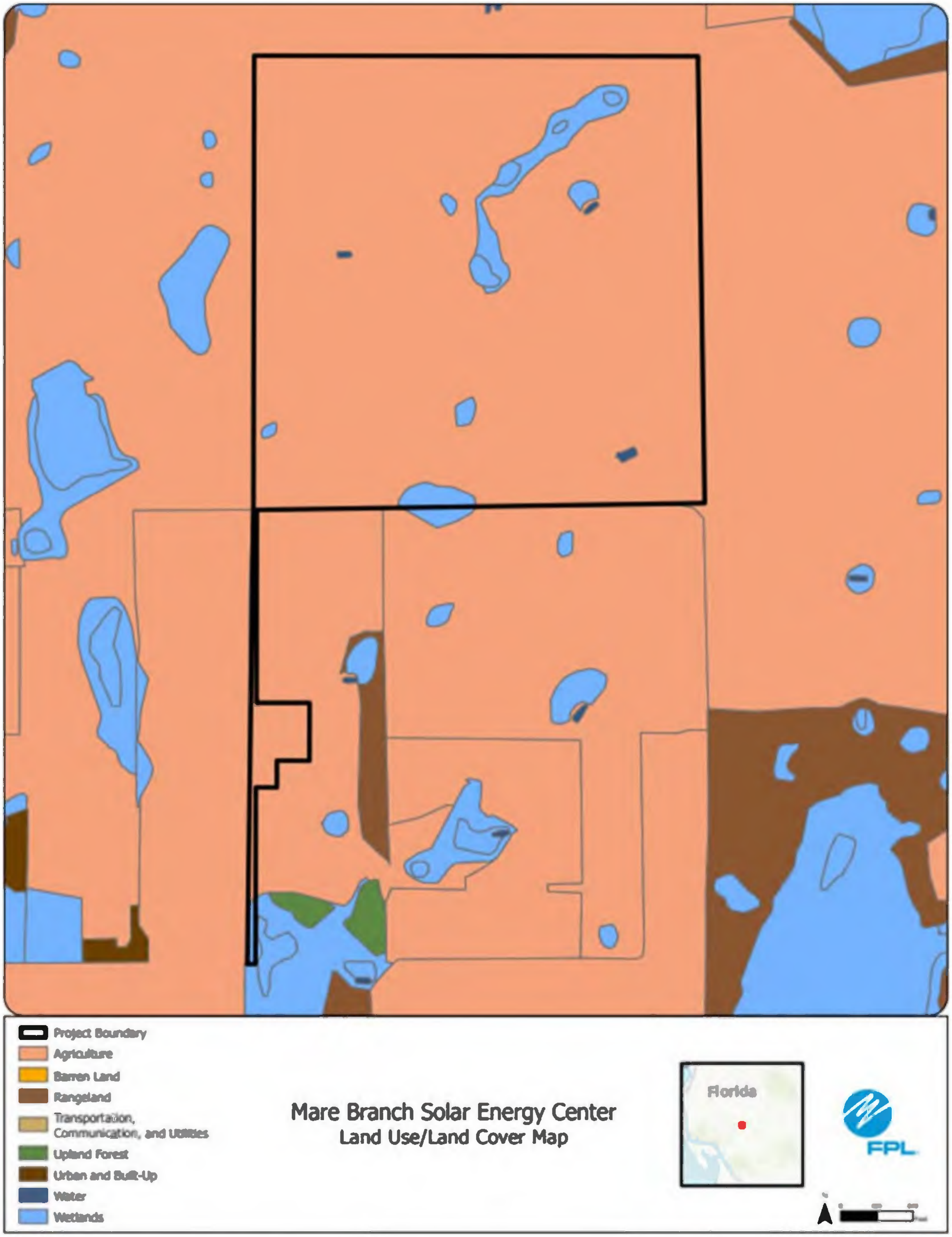
Mare Branch Solar Energy Center
Mare Branch Solar Energy Center
USGS Topography Map
Florida
FPL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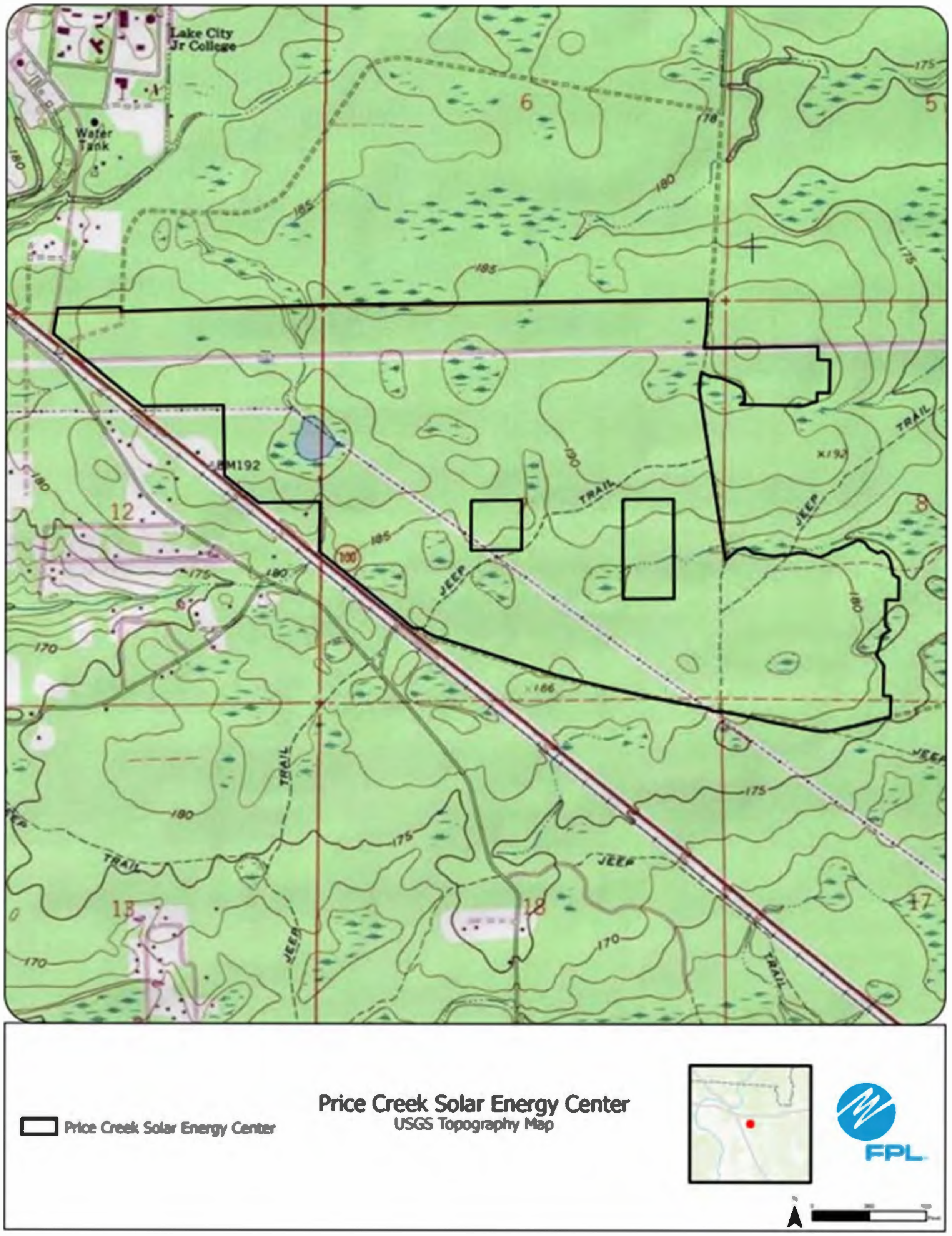
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Mare Branch Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Mare Branch Solar Energy Center
Mare Branch Solar Energy Center
Facility Layout Map
Florida
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #3: Price Creek Solar Energy Center, Columbia County

	Preferred Site	Price Creek Solar Energy Center
	County	Columbia
	Facility Acreage	792
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Primarily conifer plantation and forest regeneration areas
	Adjacent Areas	Pine trees and wetlands
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Site is primarily tree plantation and forest regeneration areas
2	Listed Species	None observed
3	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site
4	Other Significant Features	FPL Duval-Raven 230kV Transmission line along N boundary, Lake Butler-Price 115kV transmission line from NW to SE across property. Georgia Southern and Florida Railroad defines SW boundary. Community of Lulu 1.75 S of property
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figures in the following pages. Site is located in the Panhandle region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 10/30/2023 FDEP 404 GP Issued: 10/30/2023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Water
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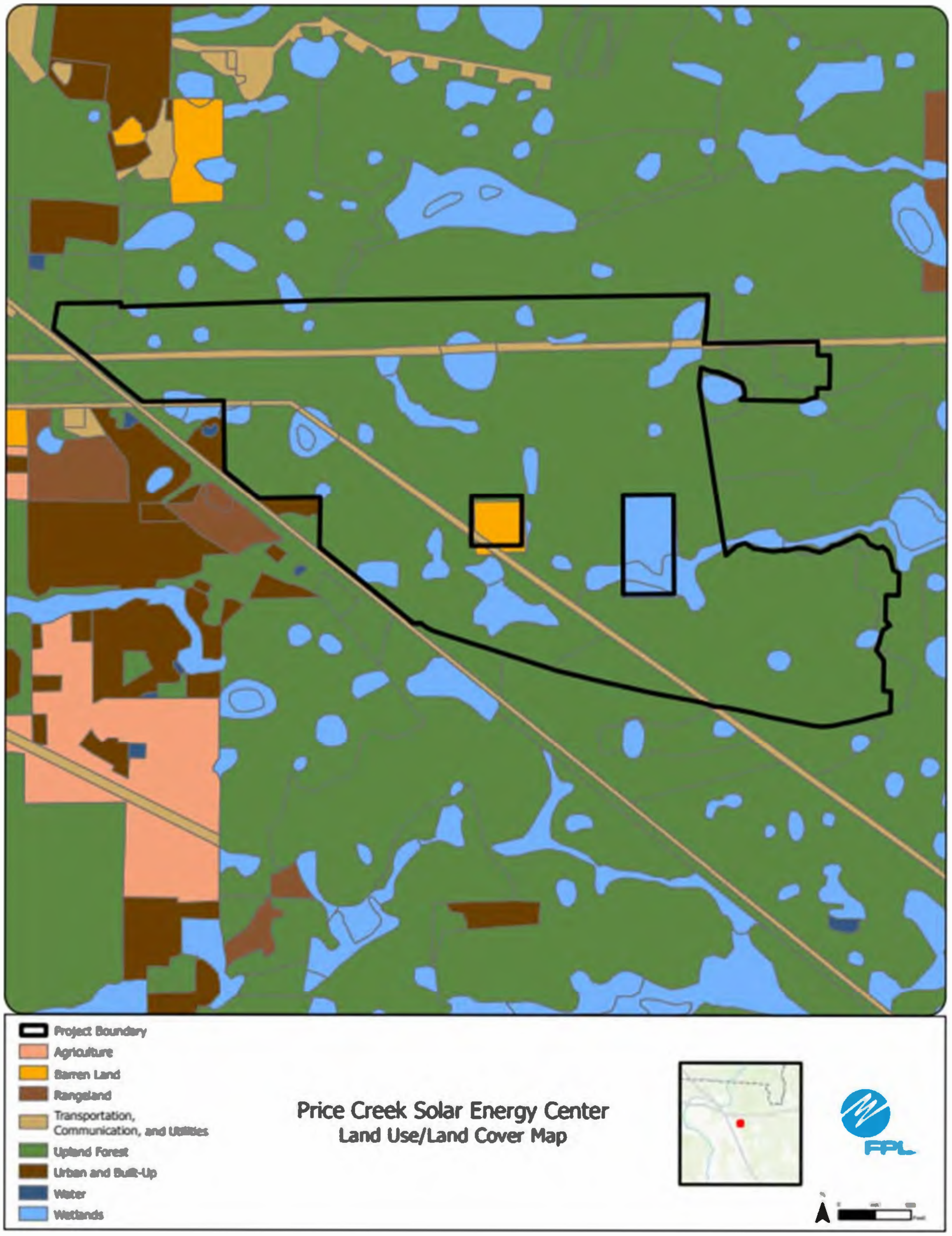
TRAIL
JEEP
Price Creek Solar Energy Center
Price Creek Solar Energy Center
USGS Topography Map
FPL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Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Price Creek Solar Energy Center
Land Use/Land Cover Map
FPL


Price Creek Solar Energy Center
Price Creek Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #4: Swamp Cabbage Solar Energy Center, Hendry County

	Preferred Site	Swamp Cabbage Solar Energy Center
	County	Hendry
	Facility Acreage	725
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Active citrus and pasture from previous citrus
	Adjacent Areas	Agricultural and low density residential
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site is primarily active citrus with pasture land from previous citrus areas
2.	Listed Species	Audubon's crested caracara, southeastern American kestrel, little blue heron, gopher tortoise
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the South region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 8/21/2023 FDEP 404 GP Issued: 8/21/2023


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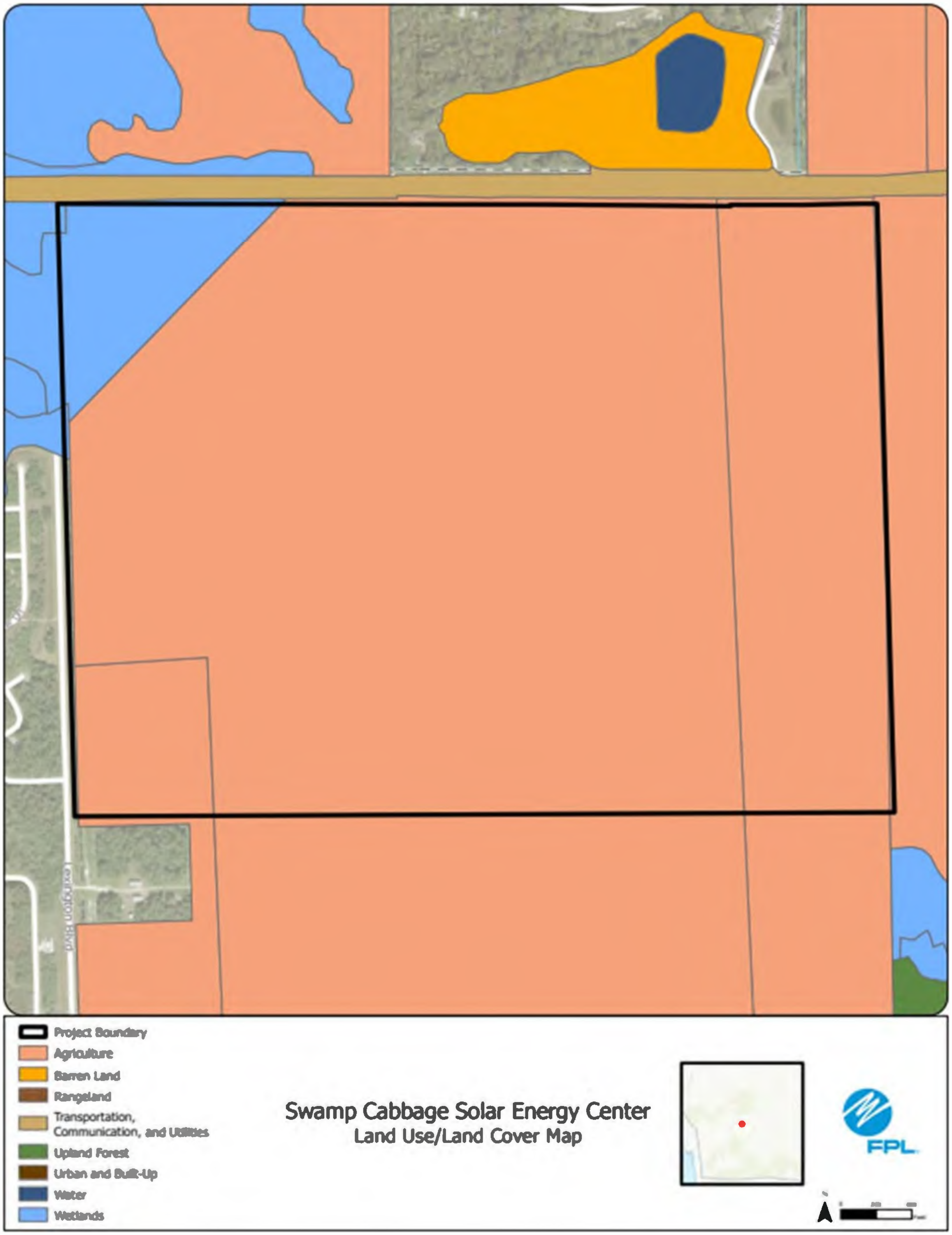
Swamp Cabbage Solar Energy Center
USGS Topography Map
Swamp Cabbage Solar Energy Center
FPL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Water
Wetlands
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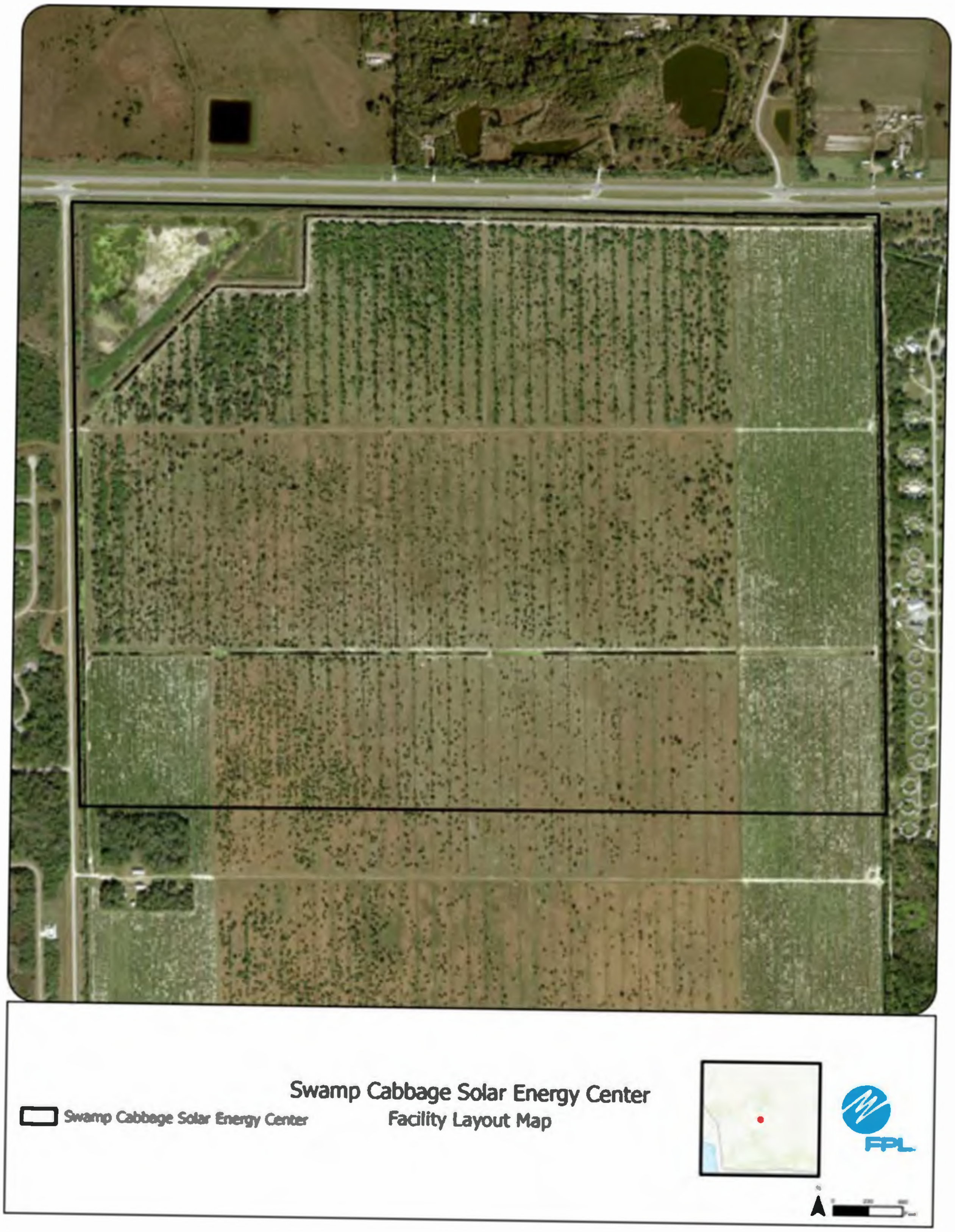
Land Use/Land Cover Map
FPL

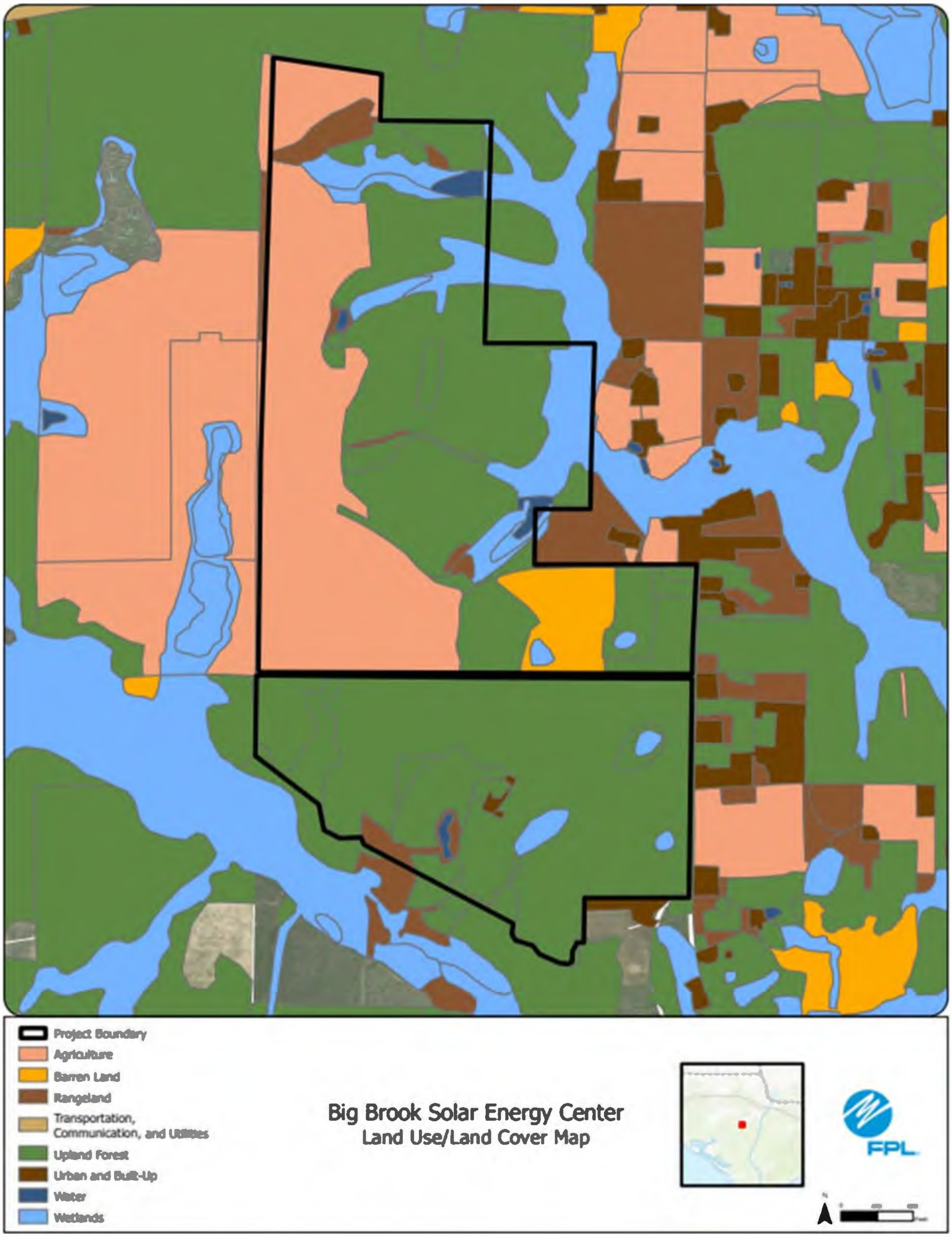

Swamp Cabbage Solar Energy Center
Facility Layout Map
Swamp Cabbage Solar Energy Center
FPL

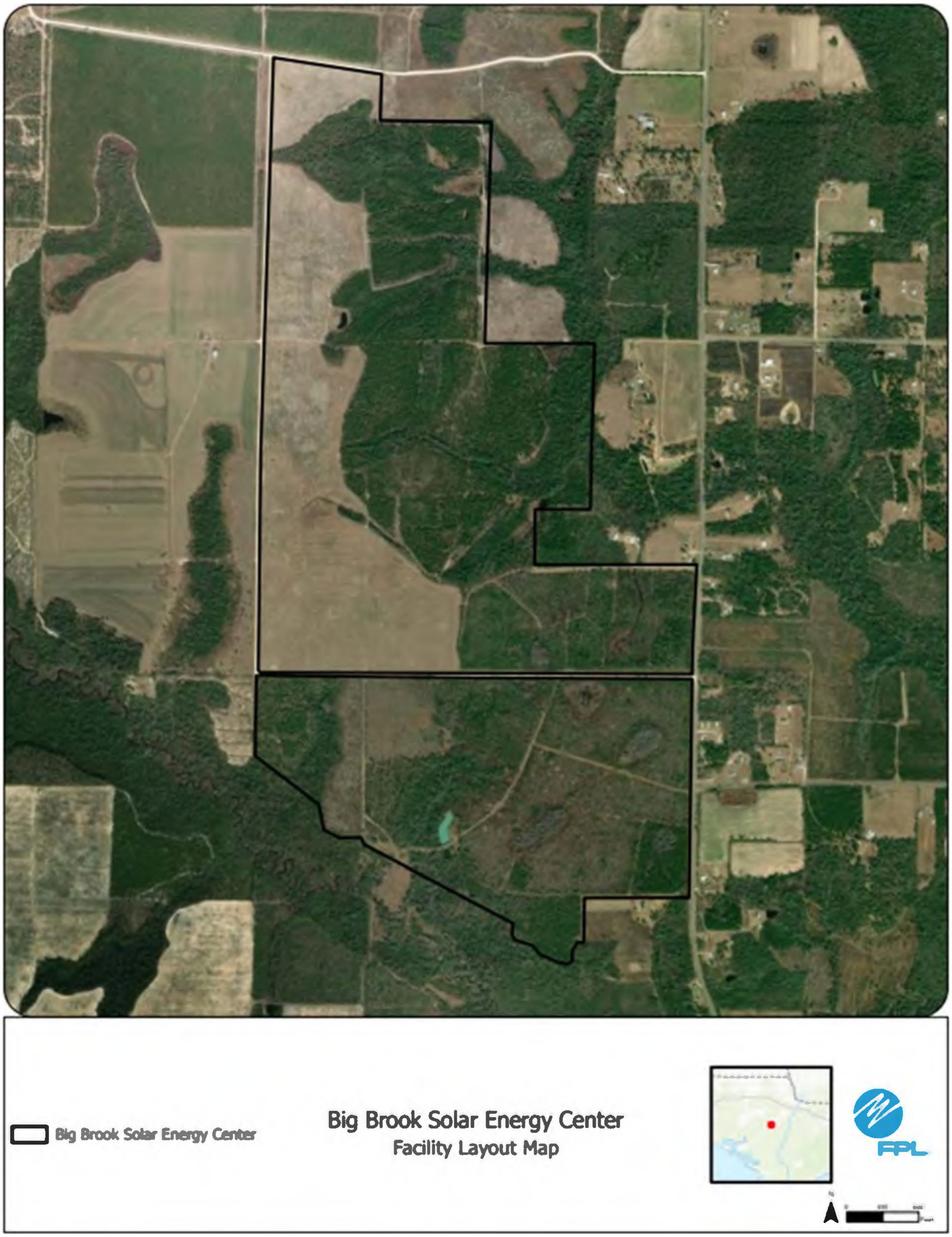
Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #5: Big Brook Solar Energy Center, Calhoun County

	Preferred Site	Big Brook Solar Energy Center
	County	Calhoun
	Facility Acreage	848
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
	Reference Maps	
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.	Existing Land Uses	
	Site	Silviculture operation / deer hunting
	Adjacent Areas	Silvicultural and residential
f.	General Environment Features on and in the Site Vicinity	
1.	Natural Environment	Site is silviculture
2.	Listed Species	Gopher tortoise, eastern indigo snake
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figures in the following pages. Site is located in the Panhandle region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 3/25/2024


Big Brook Solar Energy Center
USGS Topography Map
Big Brook Solar Energy Center
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Big Brook Solar Energy Center
Land Use/Land Cover Map
FPL


Big Brook Solar Energy Center
Big Brook Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #6: Mallard Solar Energy Center, Brevard County

	Preferred Site	Mallard Solar Energy Center
	County	Brevard
	Facility Acreage	456
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Agriculture
	Adjacent Areas	Various agriculture
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Agriculture
2	Listed Species	No adverse impacts to listed species are anticipated.
3	Natural Resources of Regional Significance Status	None
4	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the South region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 7/24/2024


Flowing Well
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Flowing Well
Flowing Well
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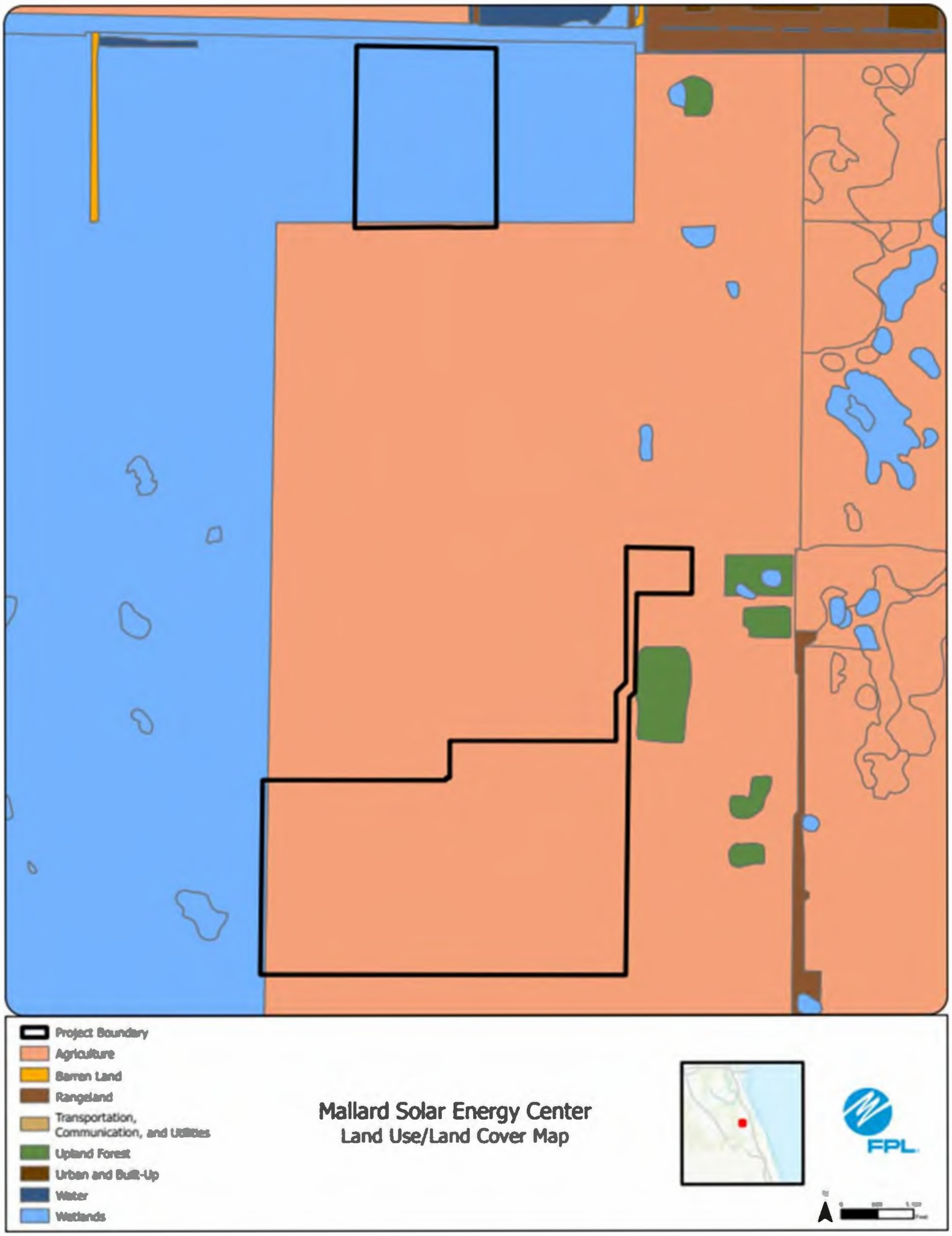
LEVEE
Mallard Solar Energy Center
Mallard Solar Energy Center
USGS Topography Map
FPL

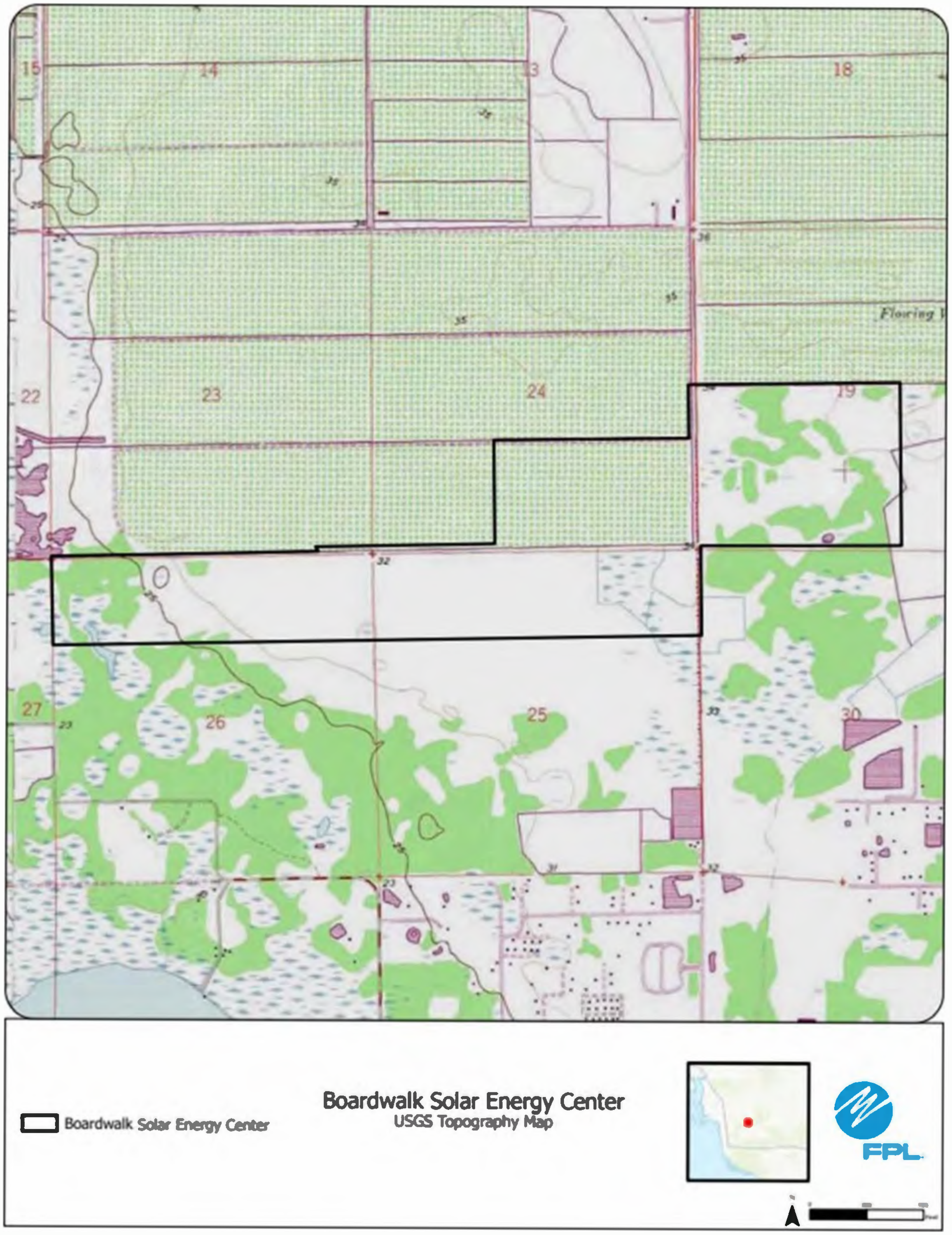

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Mallard Solar Energy Center
Land Use/Land Cover Map
FPL


Mallard Solar Energy Center
Mallard Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #7: Boardwalk Solar Energy Center, Collier County

	Preferred Site	Boardwalk Solar Energy Center
	County	Collier
	Facility Acreage	553
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Agriculture
	Adjacent Areas	Agriculture
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Agriculture
2.	Listed Species	No adverse impacts to listed species are anticipated.
3.	Natural Resources of Regional Significance Status	Corkscrew Swamp on the adjoining property to the west.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the South region
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 1/24/24 FDEP 404 GP Issued: 2/6/24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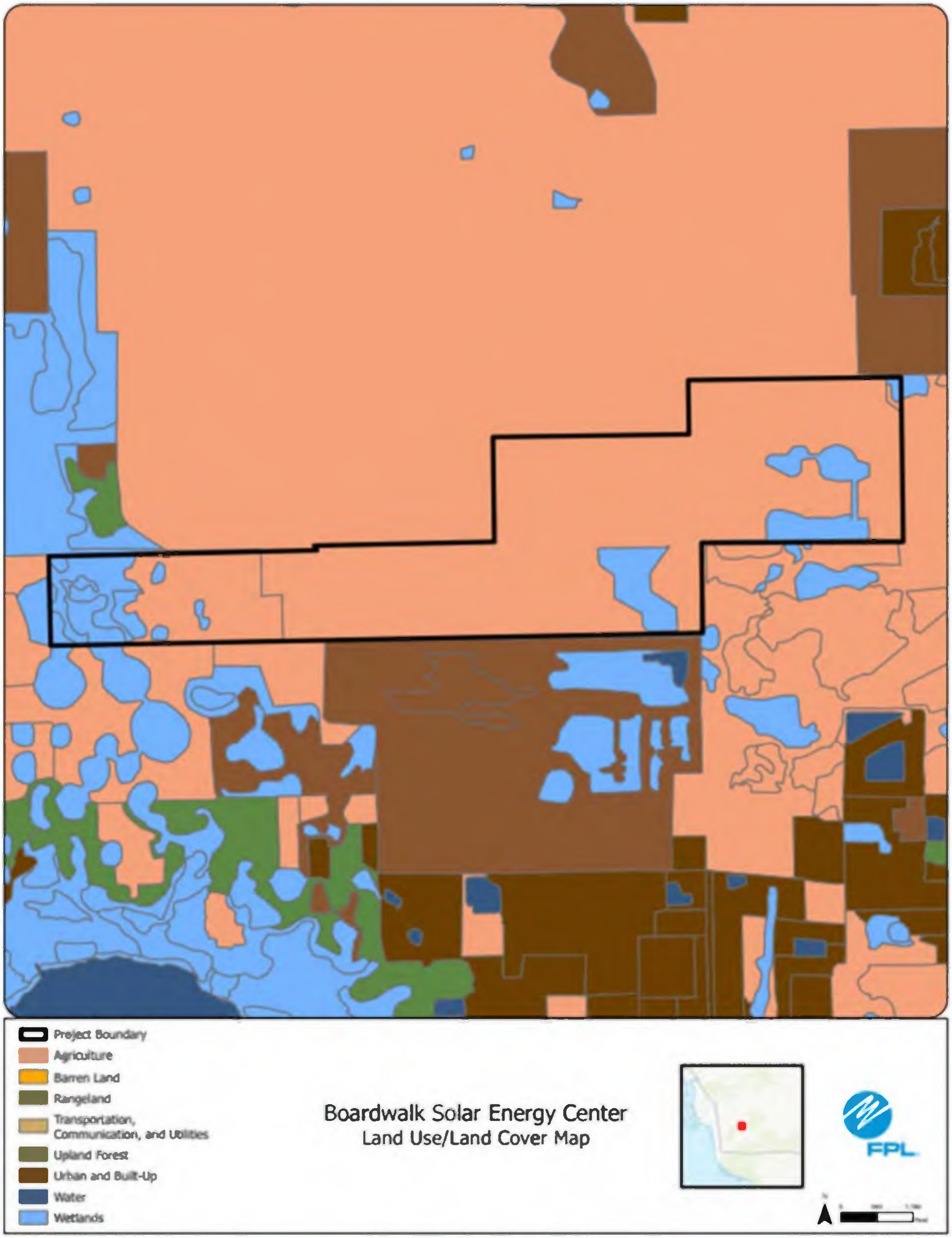
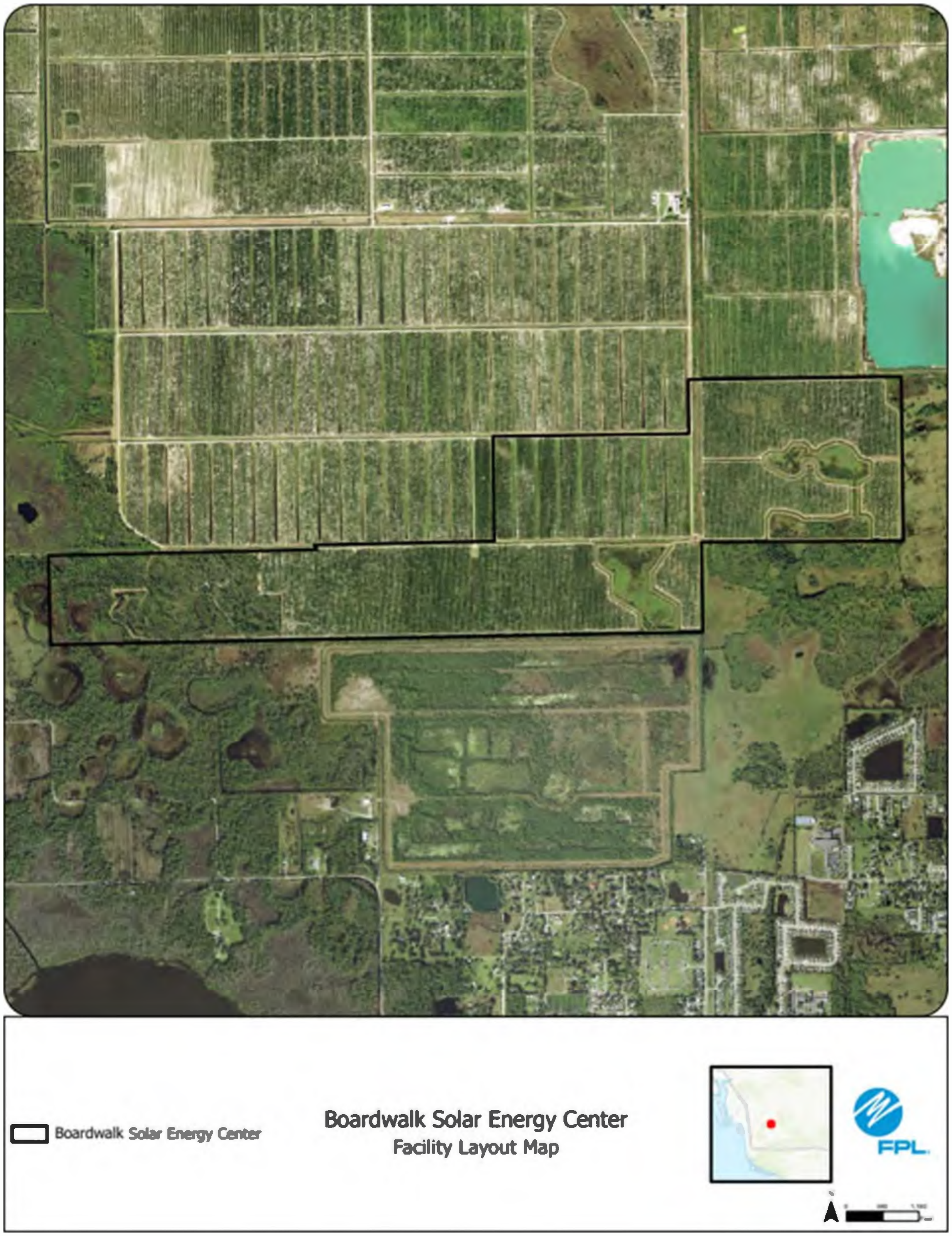
Boardwalk Solar Energy Center
Boardwalk Solar Energy Center
USGS Topography Map
FPL

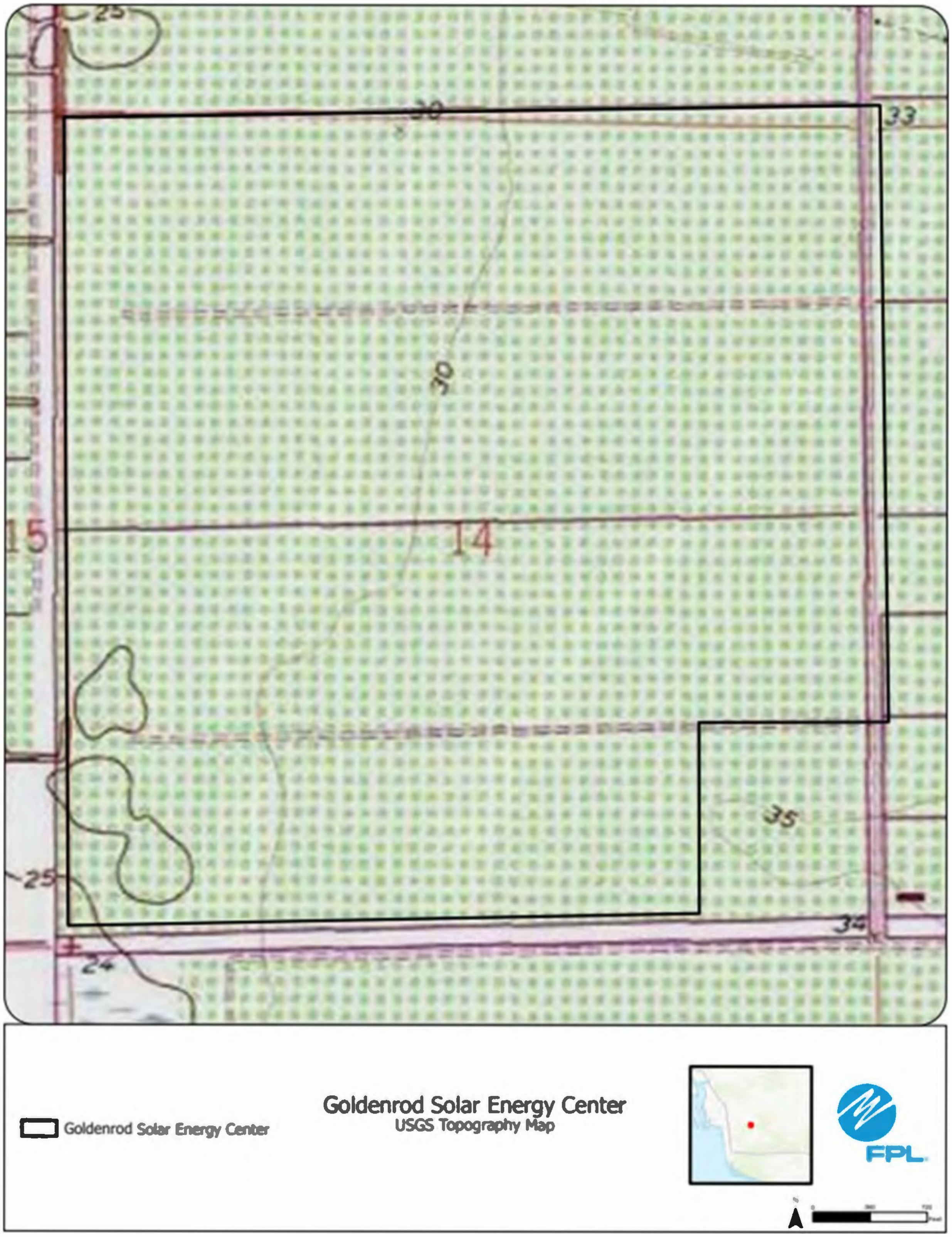

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Boardwalk Solar Energy Center
Land Use/Land Cover Map
FPL


Boardwalk Solar Energy Center
Boardwalk Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #8: Goldenrod Solar Energy Center, Collier County

	Preferred Site	Goldenrod Solar Energy Center
	County	Collier
	Facility Acreage	610
	COD	1/31/2026
	For PV facilities: tracking or fixed	Tracking
	Reference Maps	
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.	Existing Land Uses	
	Site	Agriculture
	Adjacent Areas	Agriculture
f.	General Environment Features On and In the Site Vicinity	
1.	Natural Environment	Agriculture
2	Listed Species	No adverse impacts to listed species are anticipated.
3.	Natural Resources of Regional Significance Status	Corkscrew Swamp on the adjacent property to the west.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 4/9/2024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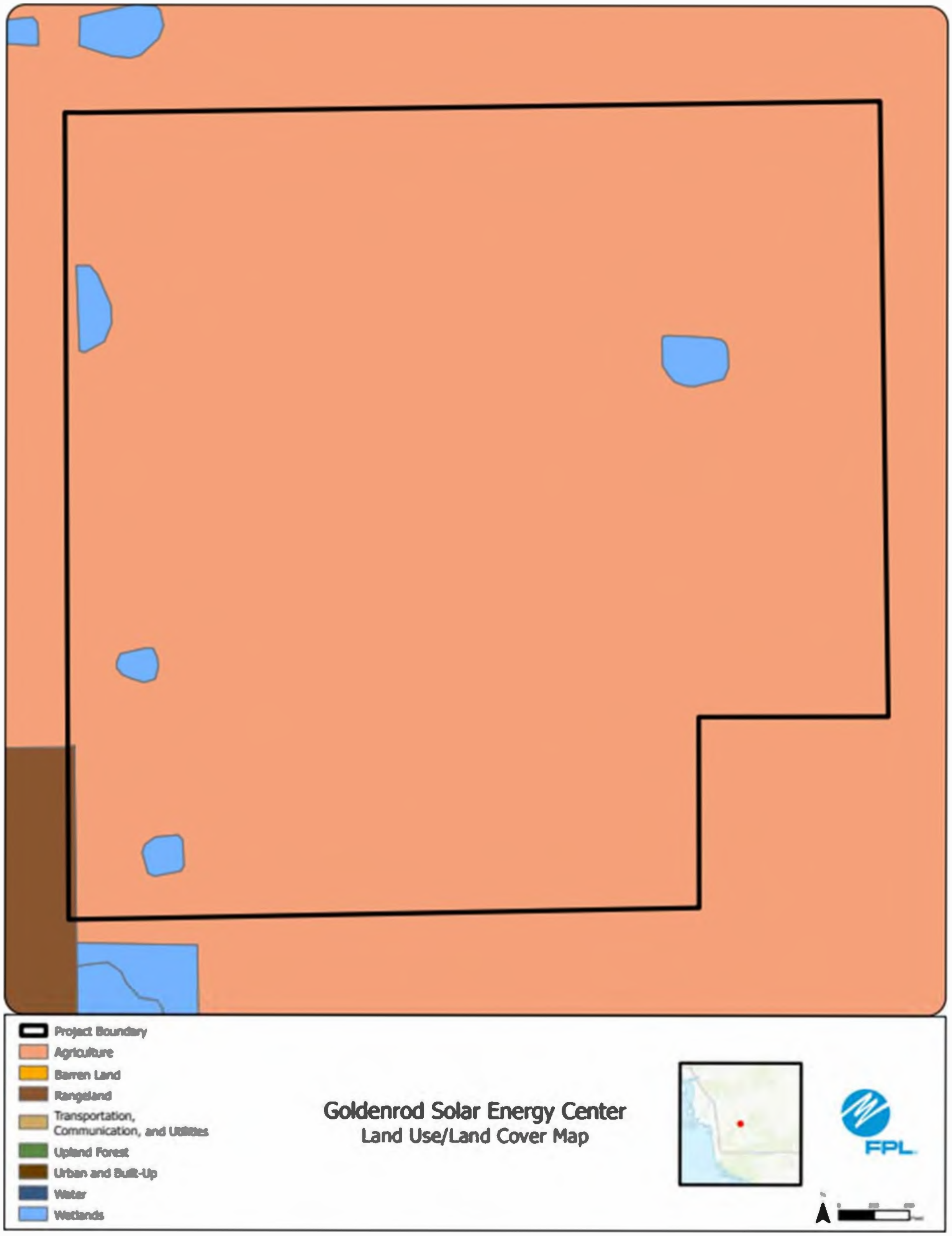
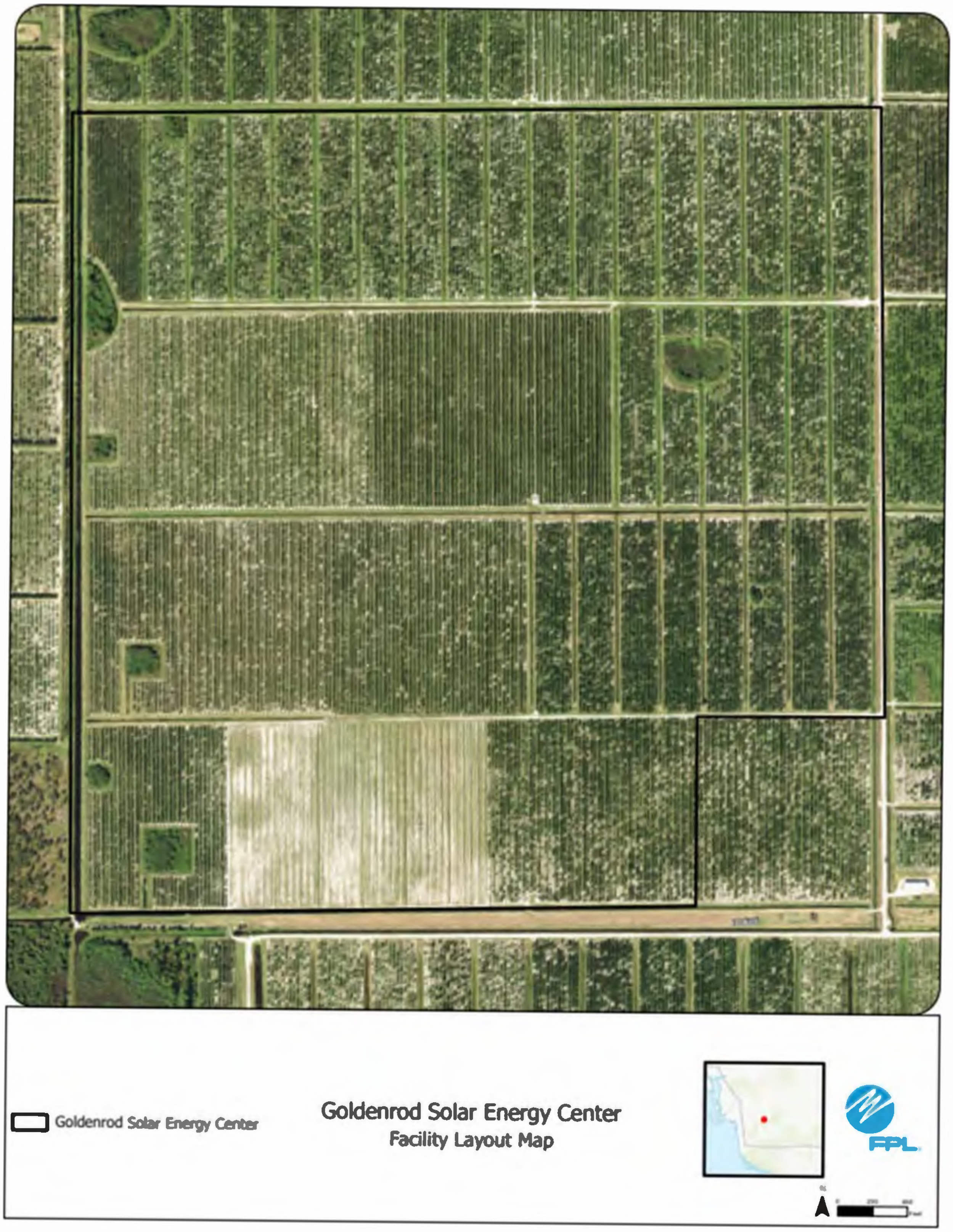
Goldenrod Solar Energy Center
Goldenrod Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Goldenrod Solar Energy Center
Land Use/Land Cover Map
FPL


Goldenrod Solar Energy Center
Goldenrod Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #9: North Orange Solar Energy Center, St. Lucie County

	Preferred Site	North Orange Solar Energy Center
	County	St. Lucie
	Facility Acreage	2037 (656 project acres)
	COD	4/30/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Previously used for agricultural purposes
	Adjacent Areas	Agriculture
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is primarily fallow cropland.
2.	Listed Species	Everglade snail kite, Florida sandhill crane, Audubon's crested caracara, wading birds
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	Formerly documented bald eagle nests to west of property
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 5/5/23 FDEP 404 GP Issued: 5/5/23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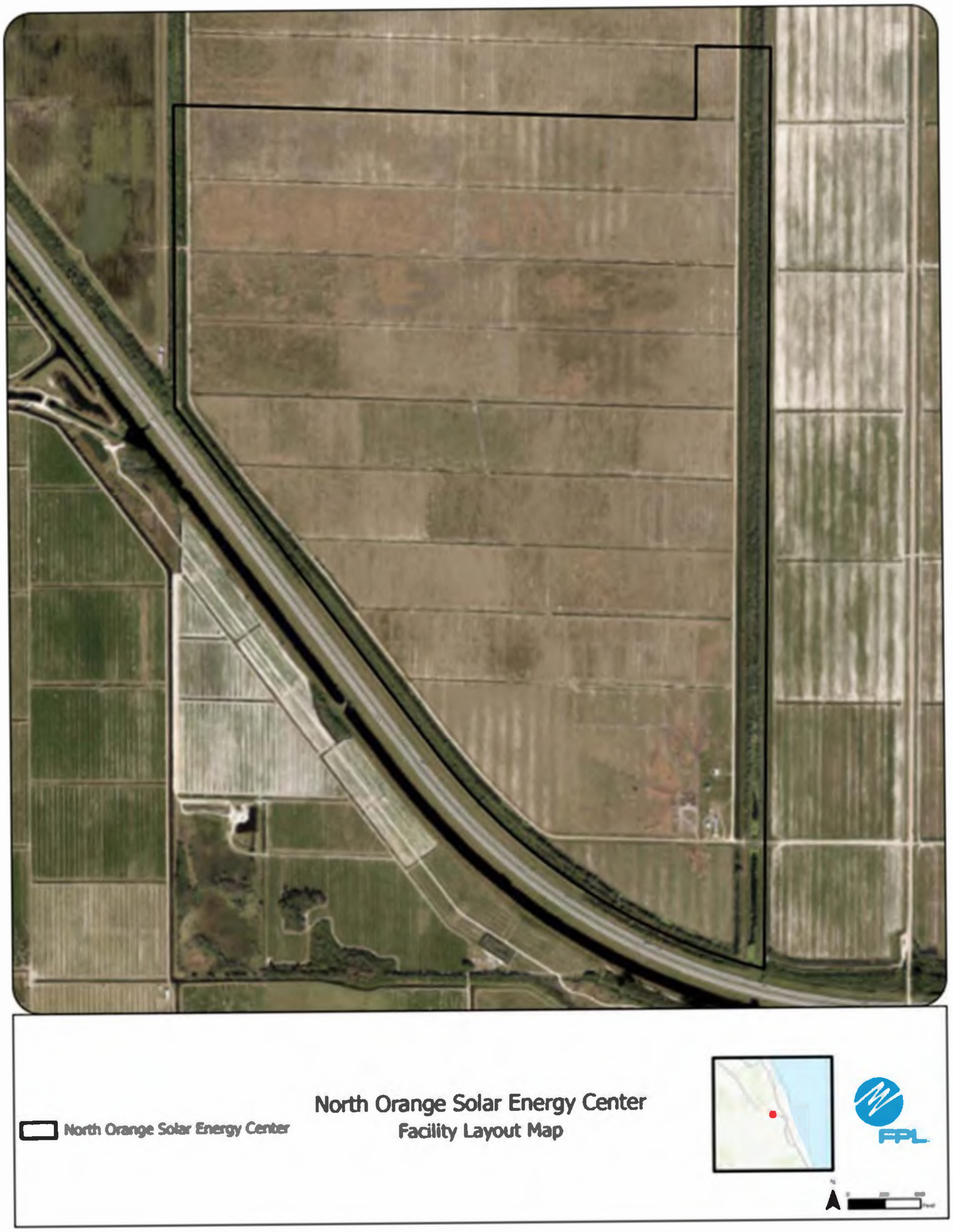
FLORIDAS TURNPIKE
TOLL ROAD
North Orange Solar Energy Center
North Orange Solar Energy Center
USGS Topography Map


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
North Orange Solar Energy Center
Land Use/Land Cover Map
FPL


North Orange Solar Energy Center
North Orange Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #10: Sea Grape Solar Energy Center, St. Lucie County

	Preferred Site	Sea Grape Solar Energy Center
	County	St. Lucie
	Facility Acreage	2037 (564 project acres)
	COD	4/30/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Inactive citrus grove, cattle
	Adjacent Areas	Agricultural, solar sites
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is primarily remnant citrus that is grazed by cattle.
2.	Listed Species	Everglade snail kite, Florida sandhill crane, Audubon's crested caracara, wading birds
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	Formerly documented bald eagle nests to west of property
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 6/26/23 FDEP 404 GP Issued: 7/5/23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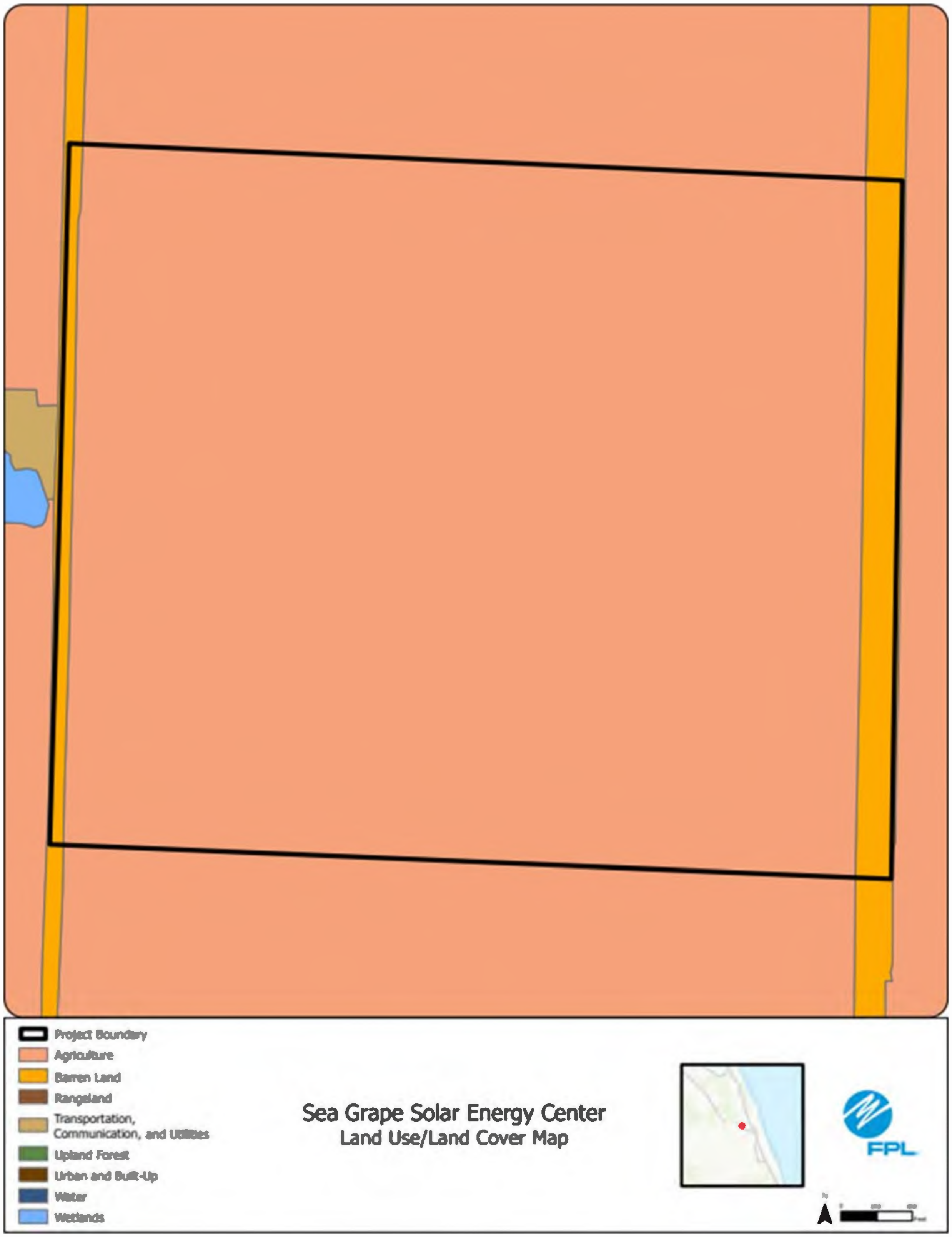
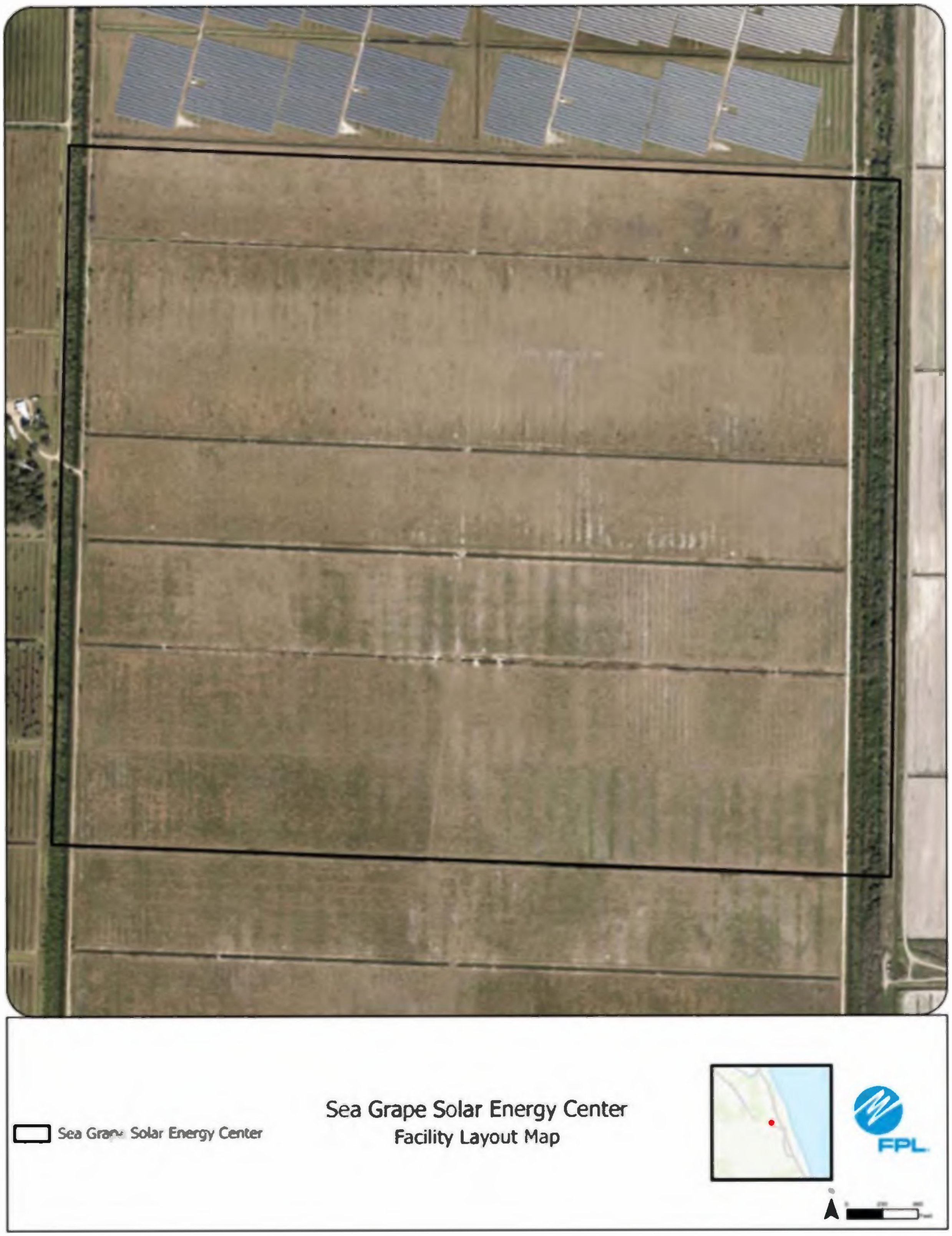
Sea Grape Solar Energy Center
Sea Grape Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Sea Grape Solar Energy Center
Land Use/Land Cover Map
FPL


Sea Grape Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #11: Clover Solar Energy Center, St. Lucie County

	Preferred Site	Clover Solar Energy Center
	County	St. Lucie
	Facility Acreage	10,341 (433 project acres)
	COD	4/30/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Improved pasture
	Adjacent Areas	Fallow agriculture, improved pasture, C-25 canal
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	The entire property consists of improved pasture with agricultural ditches.
2.	Listed Species	Audubon's crested caracara, wading birds
3.	Natural Resources of Regional Significance Status	C-25 canal is located immediately south of the project.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 6/12/2024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X24
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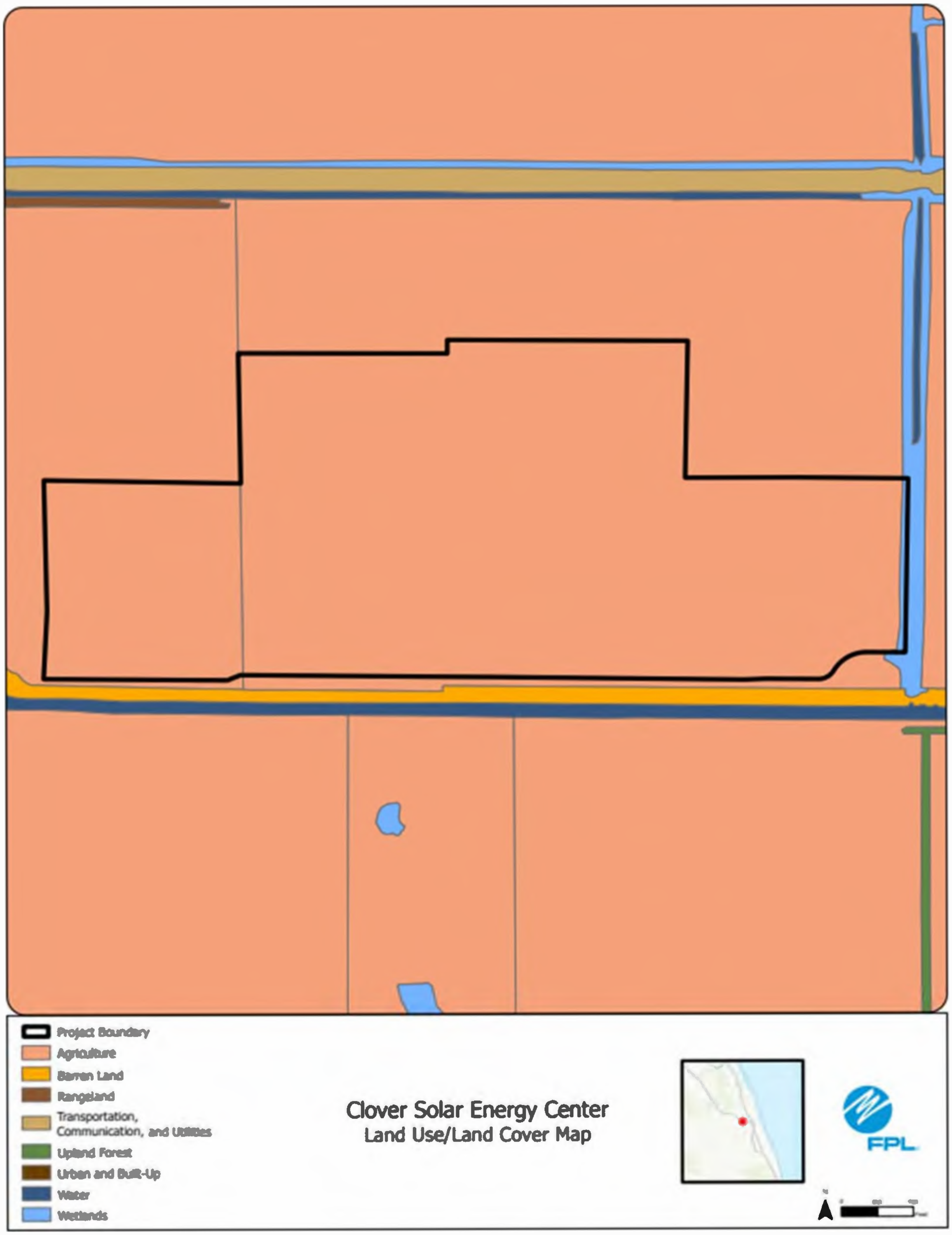
Clover Solar Energy Center
Clover Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Clover Solar Energy Center
Land Use/Land Cover Map
FPL

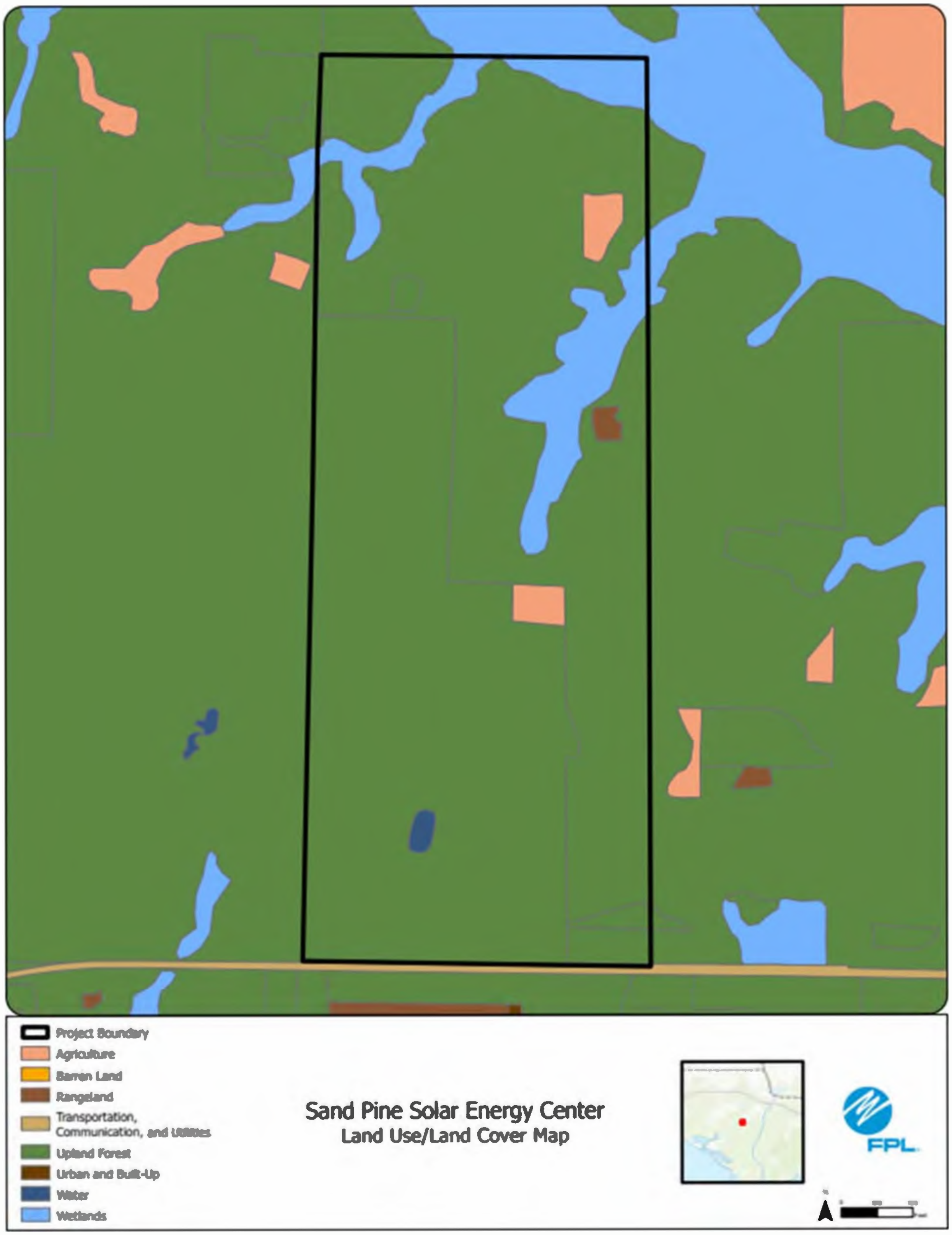

Clover Solar Energy Center
Clover Solar Energy Center
Facility Layout Map
FPL

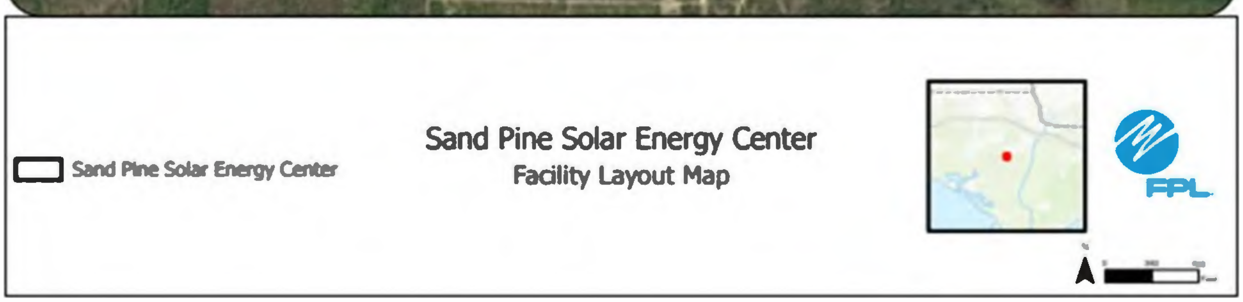
Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #12: Sand Pine Solar Energy Center, Calhoun County

	Preferred Site	Sand Pine Solar Energy Center
	County	Calhoun
	Facility Acreage	719
	COD	4/30/2026
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Silviculture, hunting
	Adjacent Areas	Timber, croplands, horse farms, solar
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site is primarily silviculture.
2.	Listed Species	Gopher tortoise
3.	Natural Resources of Regional Significance Status	Chipola Experimental Forest and Juniper Creek Wildlife Management Area to South of property.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the Panhandle region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 8/24/2023


Sand Pine Solar Energy Center
Sand Pine Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Sand Pine Solar Energy Center
Land Use/Land Cover Map
FPL


Sand Pine Solar Energy Center
Sand Pine Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #13: Hendry Solar Energy Center, Hendry County

	Preferred Site	Hendry Solar Energy Center
	County	Hendry
	Facility Acreage	641
	COD	1/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Improved pasture and wetlands
	Adjacent Areas	Various crop agriculture
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Site is actively used as improved pasture with a few wetlands and agricultural ditches.
2	Listed Species	Audubon's crested caracara, gopher tortoise
3	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 1/10/24 FDEP 404 GP Issued: 1/10/24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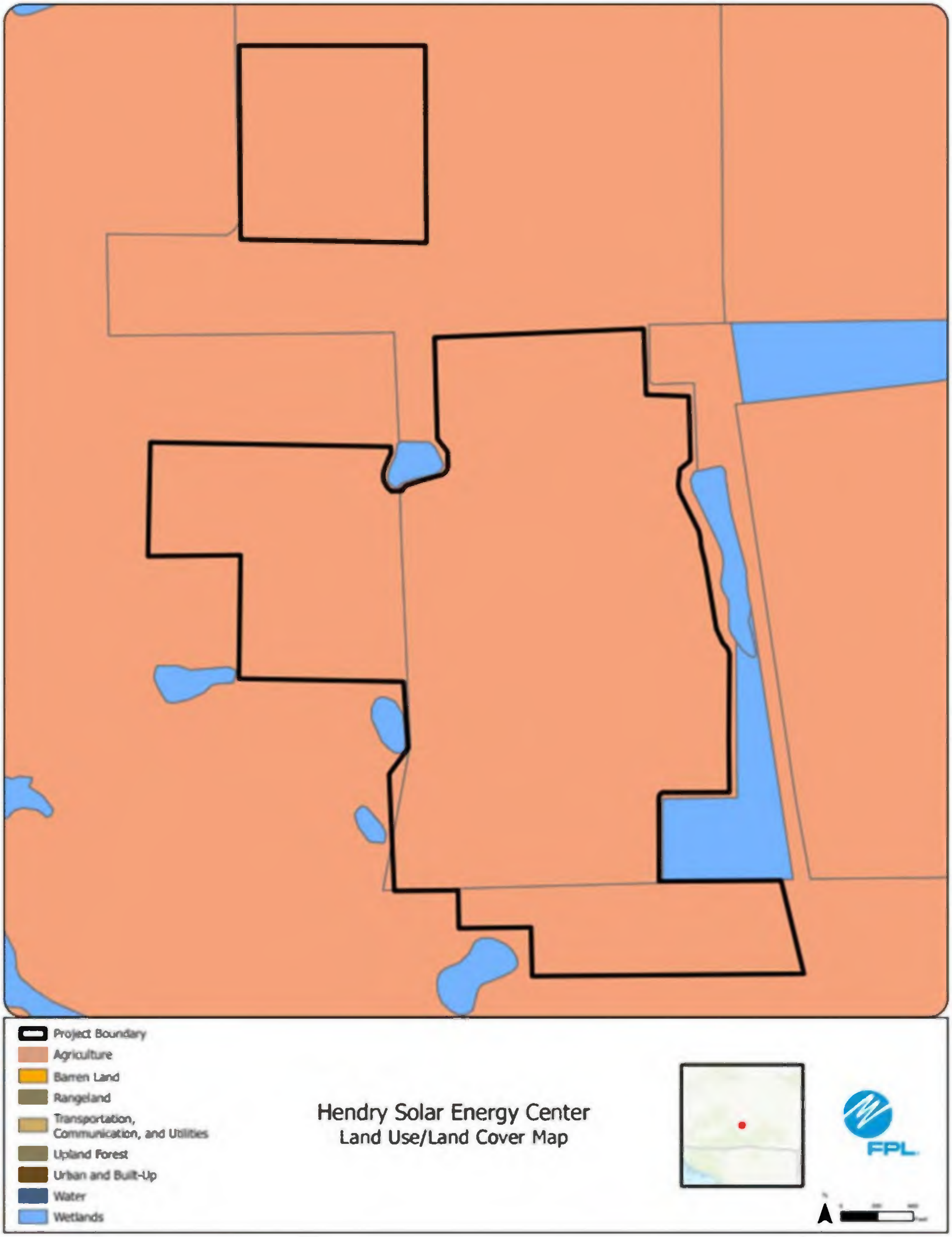
Hendry Solar Energy Center
Hendry Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Hendry Solar Energy Center
Land Use/Land Cover Map
FPL


Hendry Solar Energy Center
Hendry Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #14: Tangelo Solar Energy Center, Okeechobee County

	Preferred Site	Tangelo Solar Energy Center
	County	Okeechobee
	Facility Acreage	748
	COD	1/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Citrus groves, improved pastures, row crops, forested wetlands, agricultural ditches
	Adjacent Areas	Citrus and Sand Hill Rock mining
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	The upland use is predominantly improved pasture. There are also forested wetlands and agricultural ditches.
2.	Listed Species	Audubon's crested caracara and wading birds
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 3/29/2024


SPOIL BANK
LEVEE
SPOIL BANK
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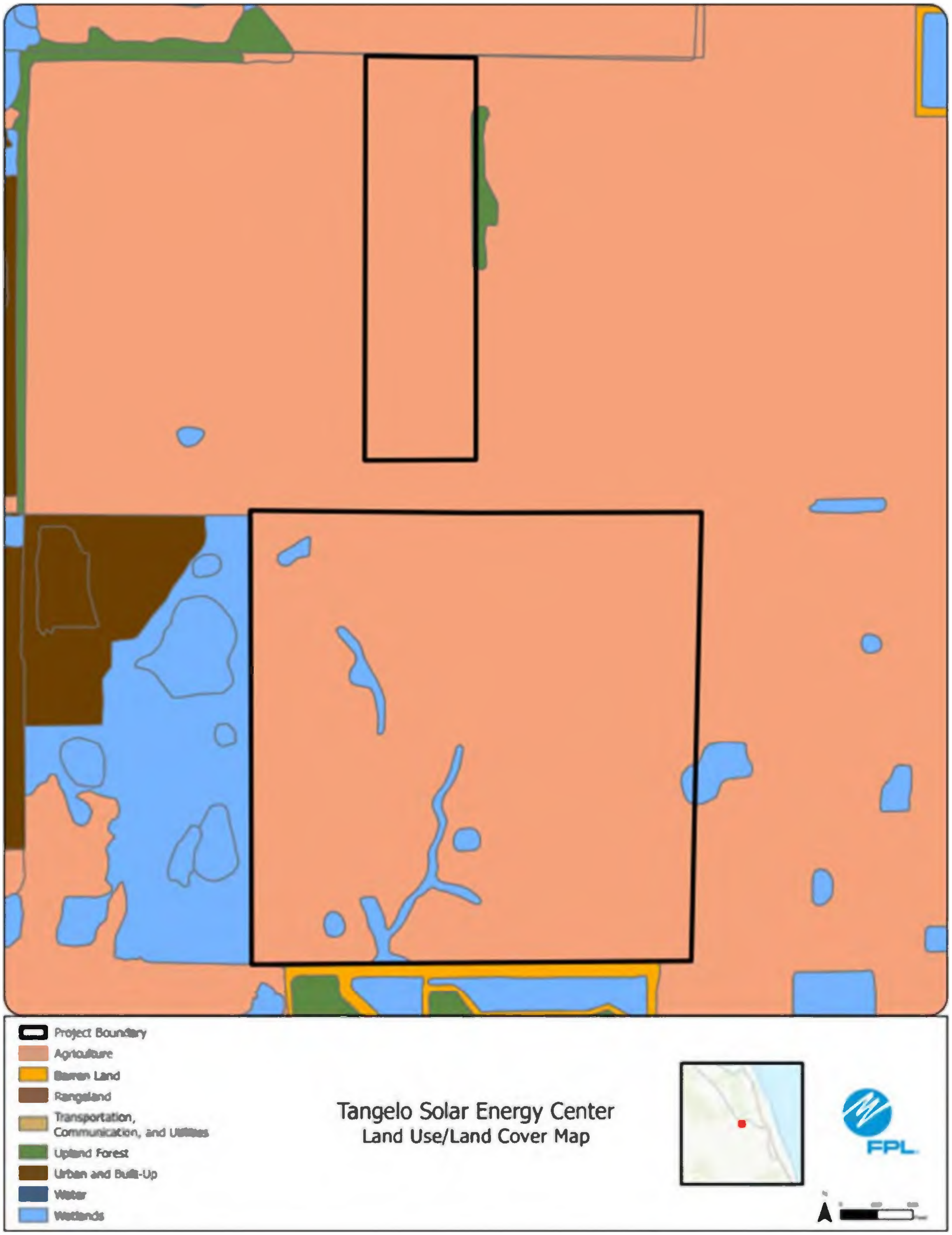
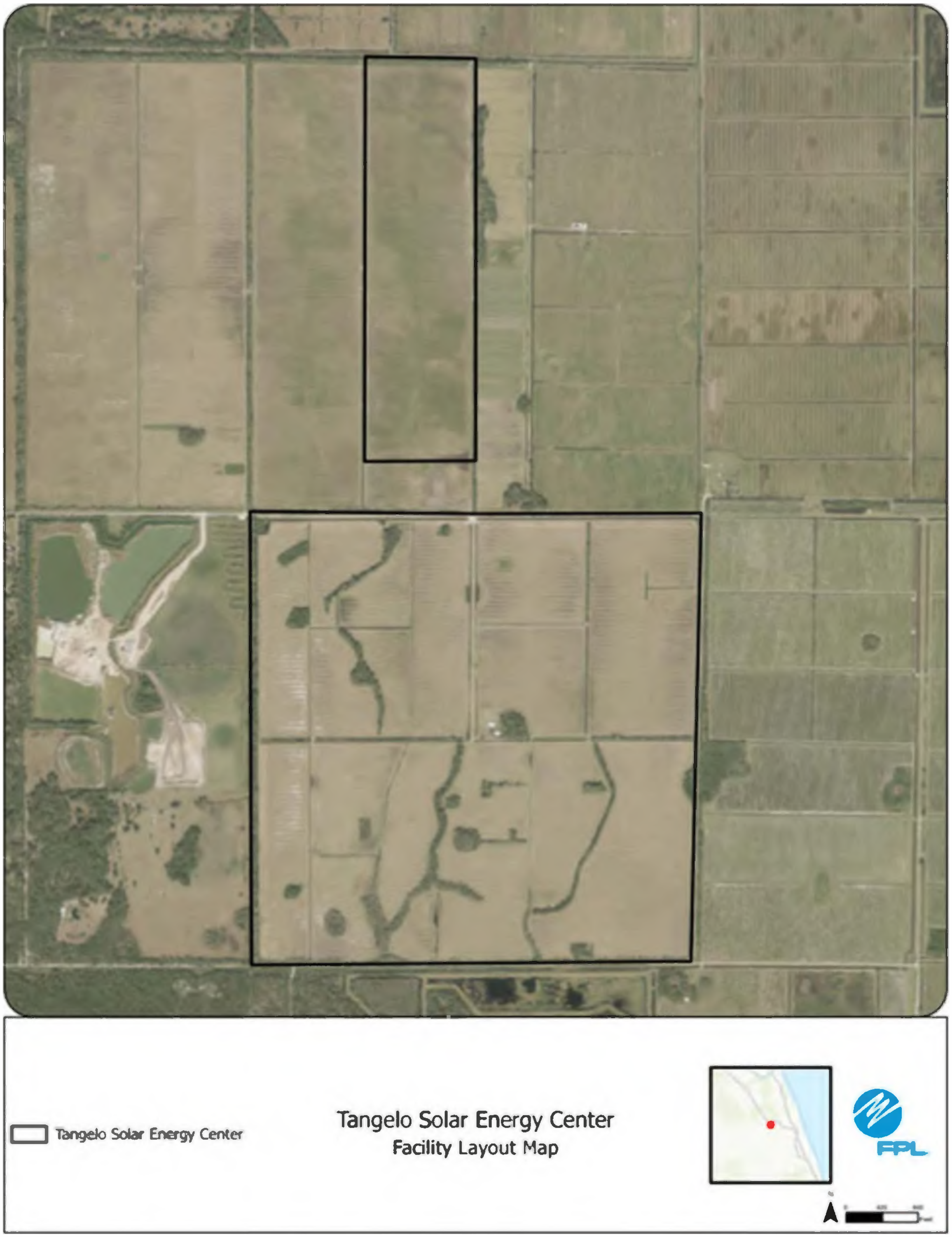
Tangelo Solar Energy Center
Tangelo Solar Energy Center
USGS Topography Map
FPL

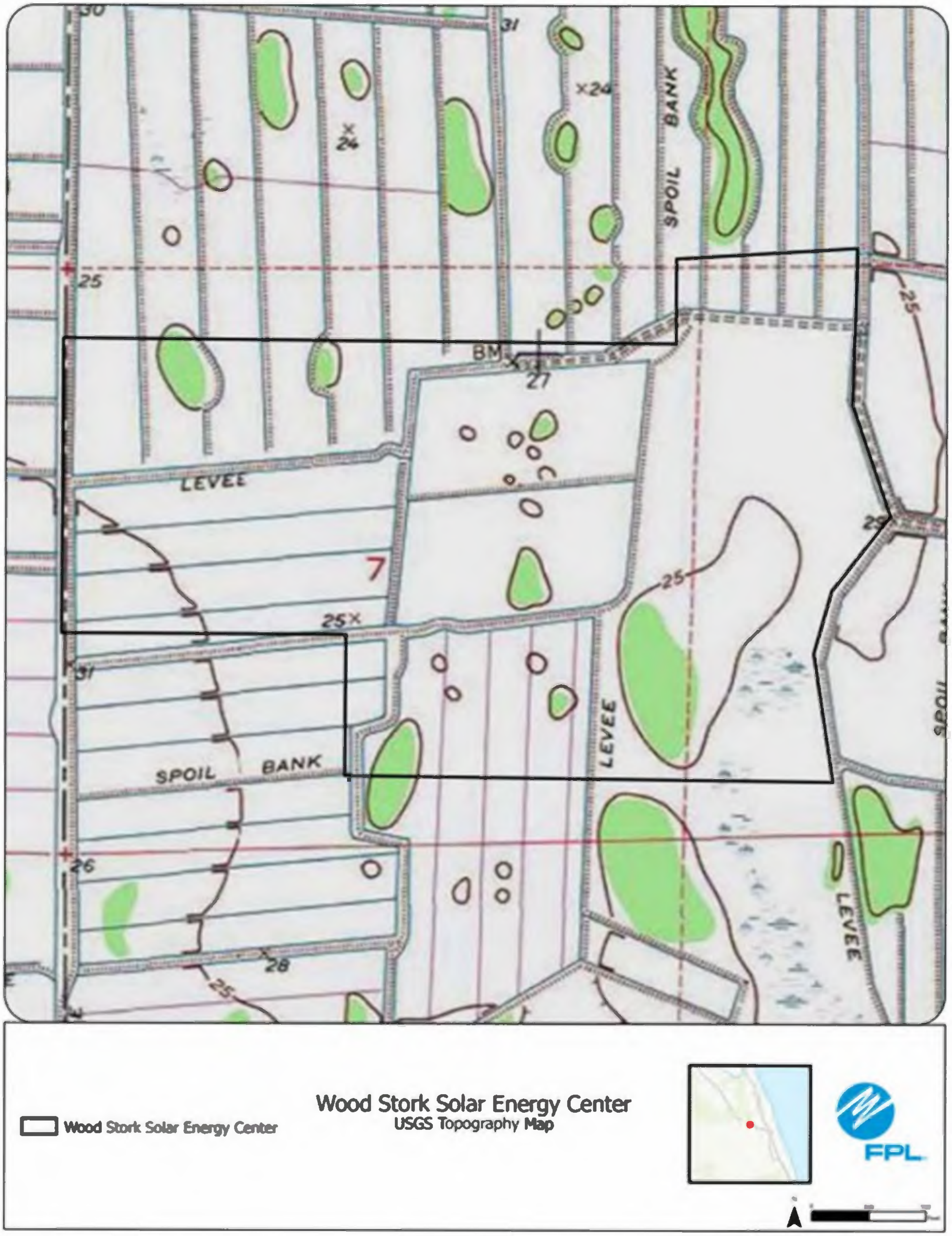

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Tangelo Solar Energy Center
Land Use/Land Cover Map
FPL

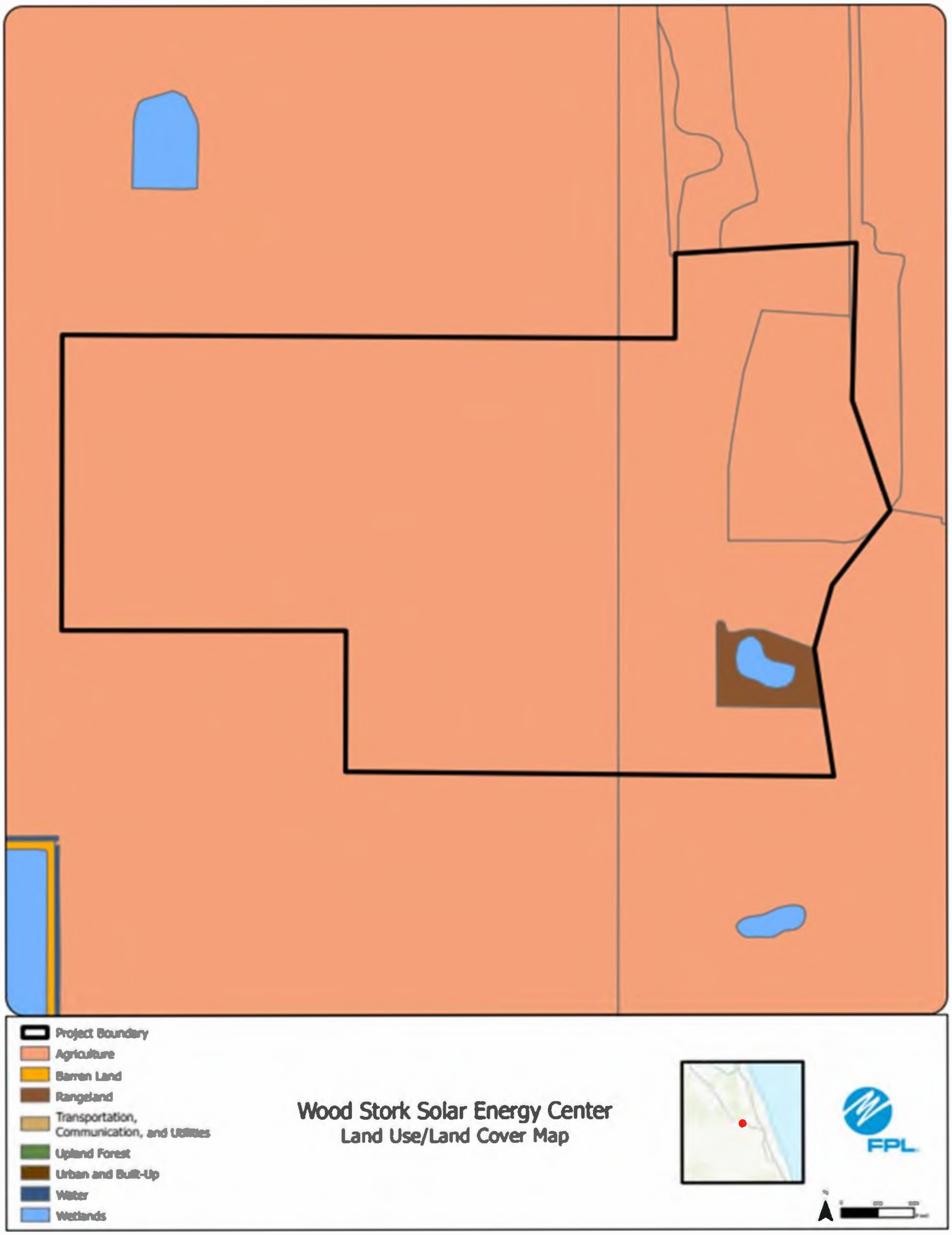

Tangelo Solar Energy Center
Tangelo Solar Energy Center
Facility Layout Map
FPL

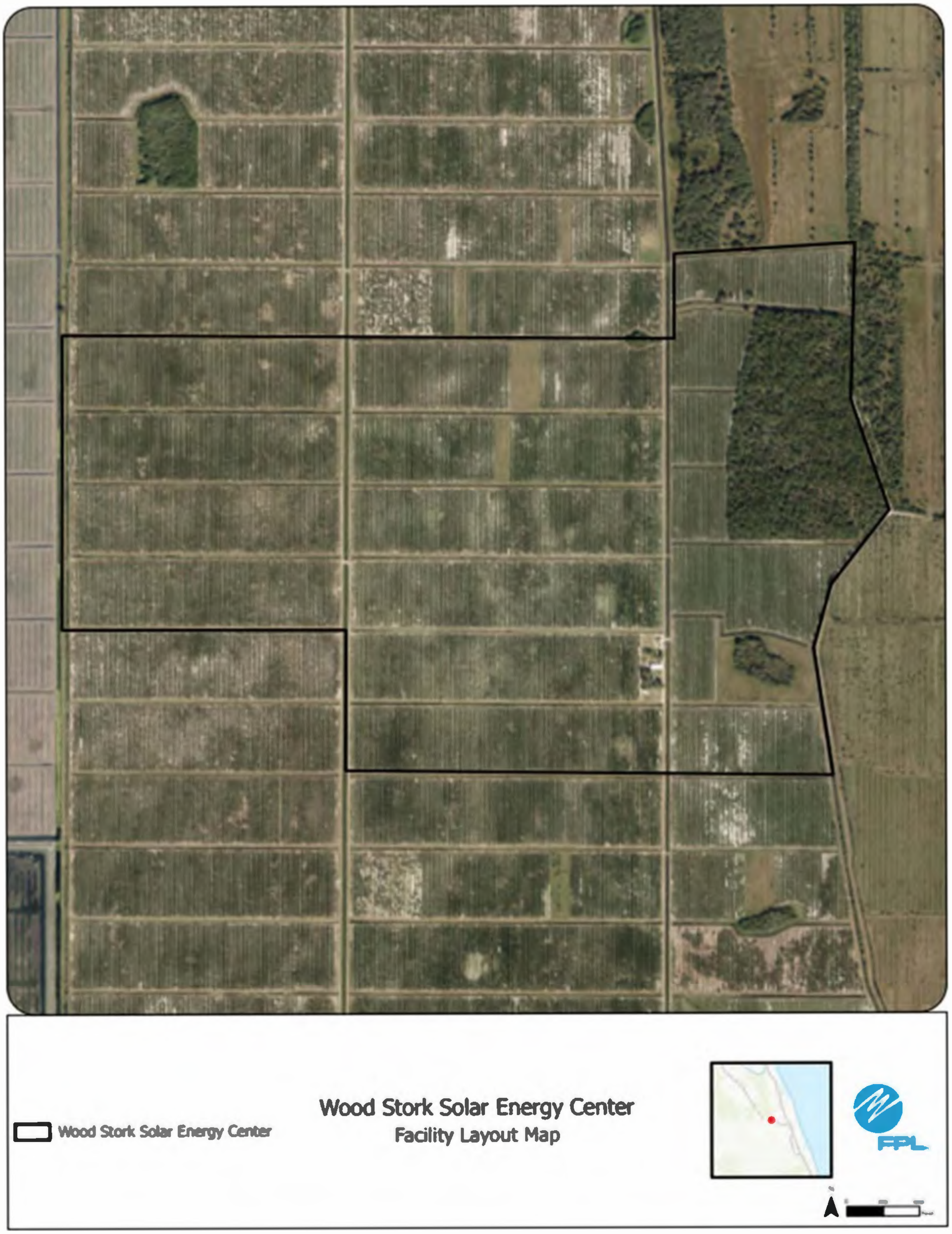
Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #15: Wood Stork Solar Energy Center, St. Lucie County

	Preferred Site	Wood Stork Solar Energy Center
	County	St. Lucie
	Facility Acreage	2831 (603 project acres)
	COD	1/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Active citrus groves
	Adjacent Areas	Citrus, pasture, crop
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Most of the property consists of active citrus groves, with a large surface water in the northern portion of the property, a few sparsely located hardwood forest areas along the eastern side of the property, and irrigation ditches occurring throughout the property.
2	Listed Species	Bald eagle, Audubon's crested caracara, wading birds
3	Natural Resources of Regional Significance Status	A documented Audubon's crested caracara nest is on site and accounted for in the project design.
4	Other Significant Features	A bald eagle nest is located northeast of the project area.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the South region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 9/28/23 FDEP 404 GP Issued: 9/28/23


LEVEE
SPOIL BANK
SPOIL BANK
LEVEE
LEVEE
BM
Wood Stork Solar Energy Center
Wood Stork Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Wood Stork Solar Energy Center
Land Use/Land Cover Map
FPL


Wood Stork Solar Energy Center
Wood Stork Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #16: Indrio Solar Energy Center, St. Lucie County

	Preferred Site	Indrio Solar Energy Center
	County	St. Lucie
	Facility Acreage	10,341 (400 project acres)
	COD	1/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Improved pasture
	Adjacent Areas	Fallow agriculture, improved pasture, above ground impoundments.
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	The entire property consists of improved pasture with agricultural ditches.
2.	Listed Species	Audubon's crested caracara, Everglade snail kite, wading birds
3.	Natural Resources of Regional Significance Status	Designated Everglade snail kite critical habitat is located immediately adjacent to the property.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 7/16/2024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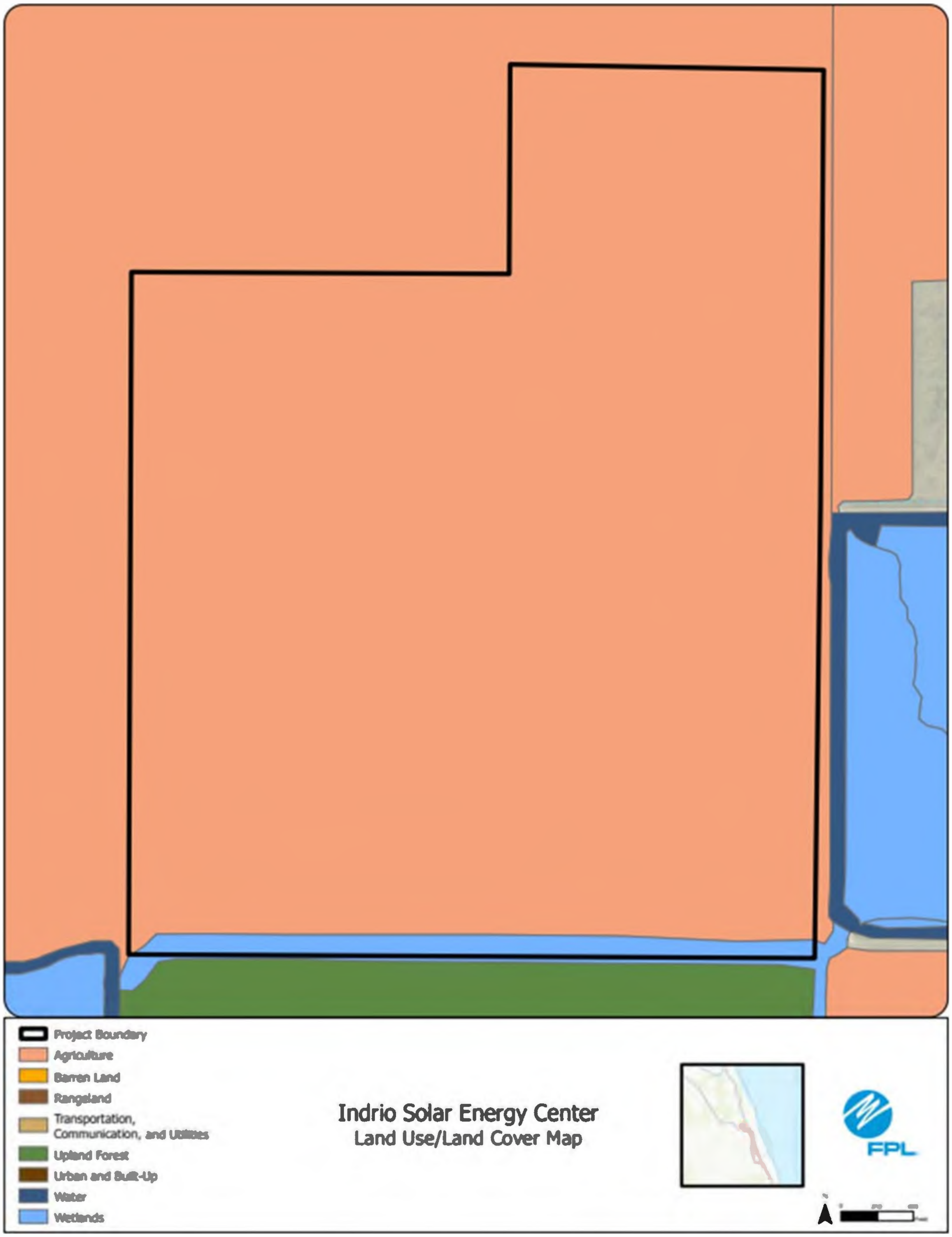
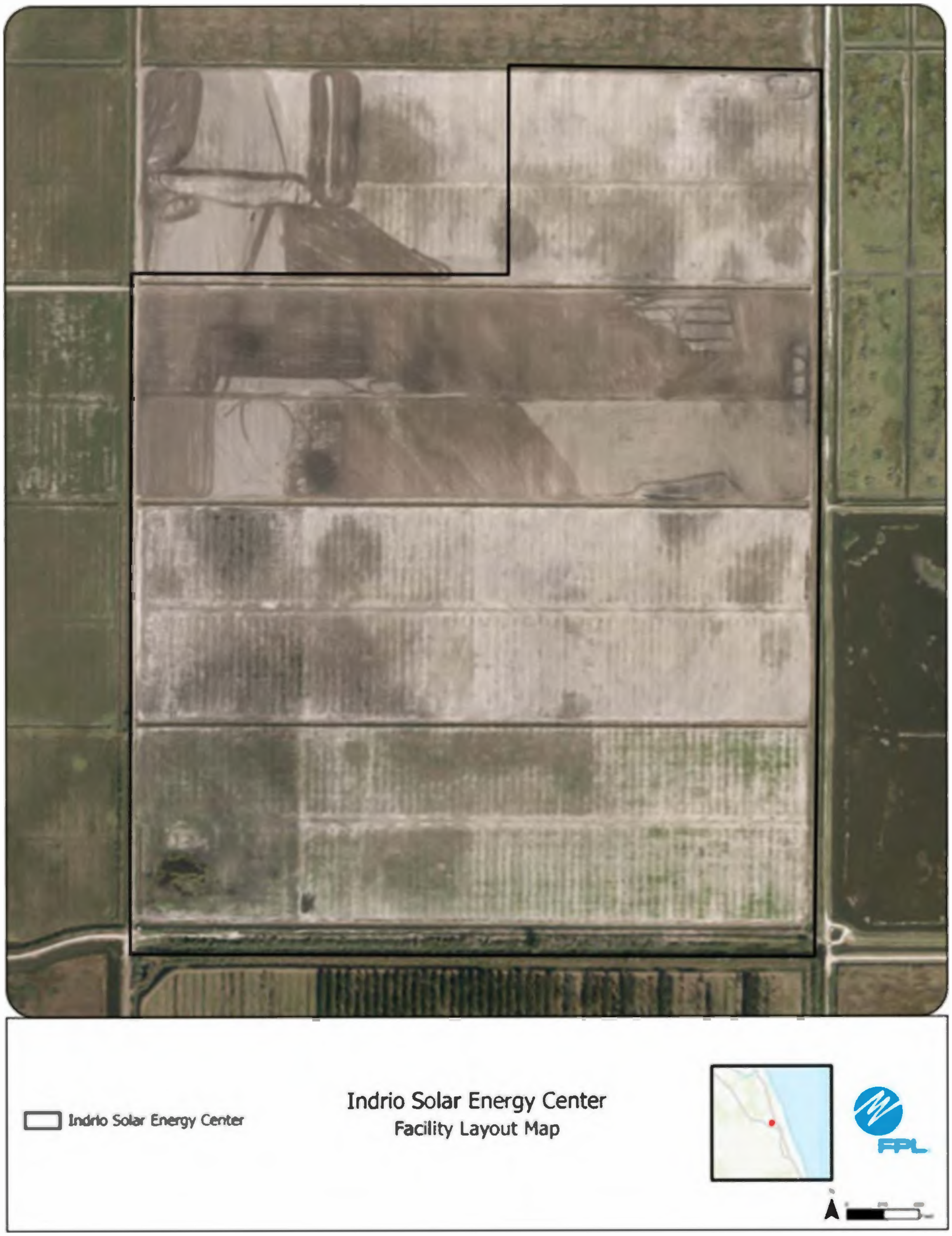
Indrio Solar Energy Center
Indrio Solar Energy Center
USGS Topography Map
FPL

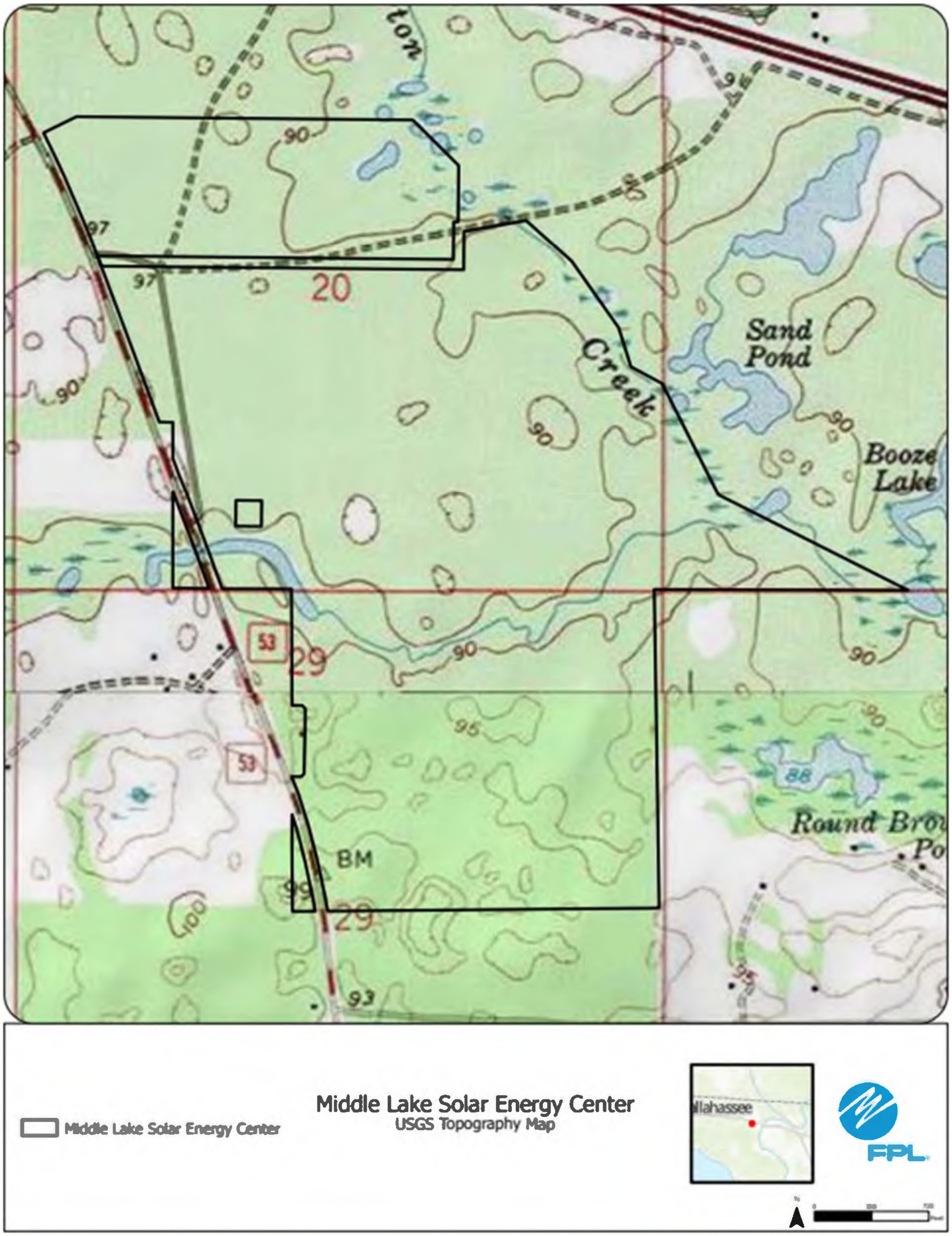

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Indrio Solar Energy Center
Land Use/Land Cover Map
FPL


Indrio Solar Energy Center
Indrio Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #17: Middle Lake Solar Energy Center, Madison County

	Preferred Site	Middle Lake Energy Center
	County	Madison
	Facility Acreage	524
	COD	4/30/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Pasture and silviculture
	Adjacent Areas	Agricultural lands, I-10 and low density residential
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is open pasture that is used for cattle and silviculture. Forested wetlands with other surface waters associated with Norton Creek.
2.	Listed Species	Bald eagle nest and gopher tortoises
3.	Natural Resources of Regional Significance Status	Norton Creek runs through this property which includes Booze Lake, Middle Lake and Peterson Sink.
4.	Other Significant Features	Karst features exist on this site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.)
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figures in the following pages. Site is located in the Panhandle region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 4/15/2024


Sand Pond
Booze Lake
Creek
Round Brow
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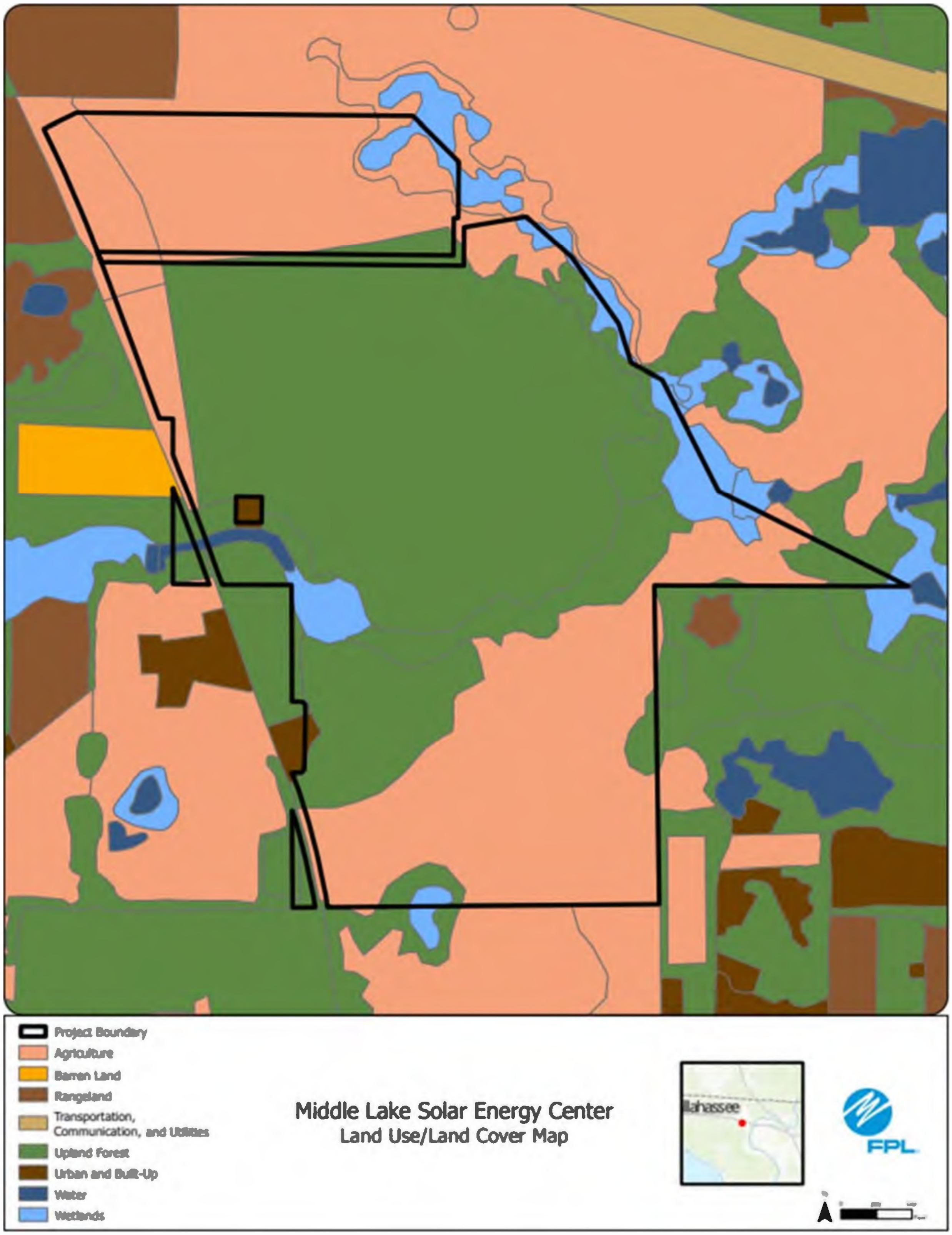
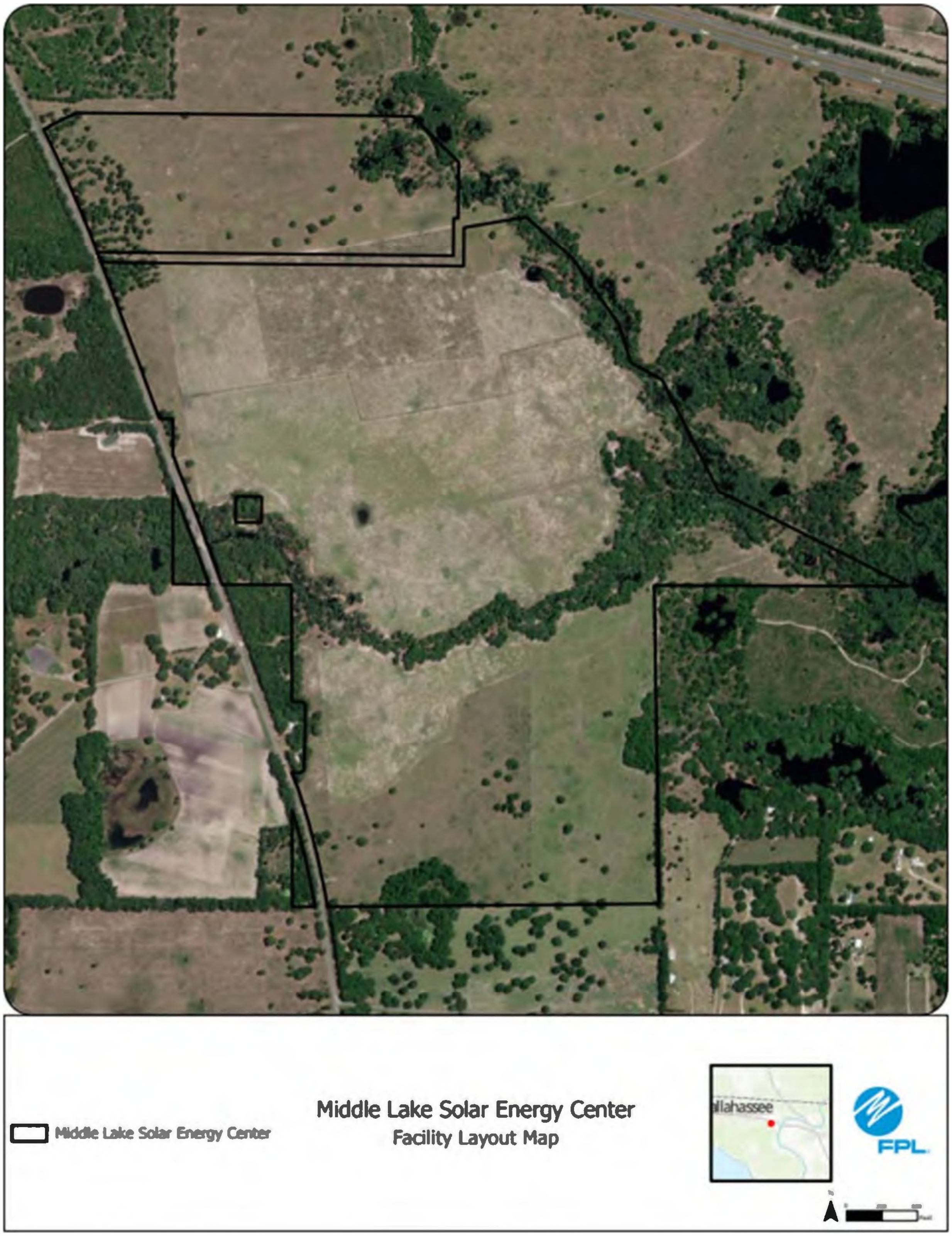
BM
Middle Lake Solar Energy Center
Middle Lake Solar Energy Center
USGS Topography Map
FPL



Middle Lake Solar Energy Center
Land Use/Land Cover Map


Middle Lake Solar Energy Center
Middle Lake Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #18: Ambersweet Solar Energy Center, Indian River County

	Preferred Site	Ambersweet Solar Energy Center
	County	Indian River
	Facility Acreage	518
	COD	4/30/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Improved pasture
	Adjacent Areas	Solar, citrus
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is entirely improved pasture with several agricultural ditches
2.	Listed Species	Audubon's crested caracara, wading birds
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 6/27/2024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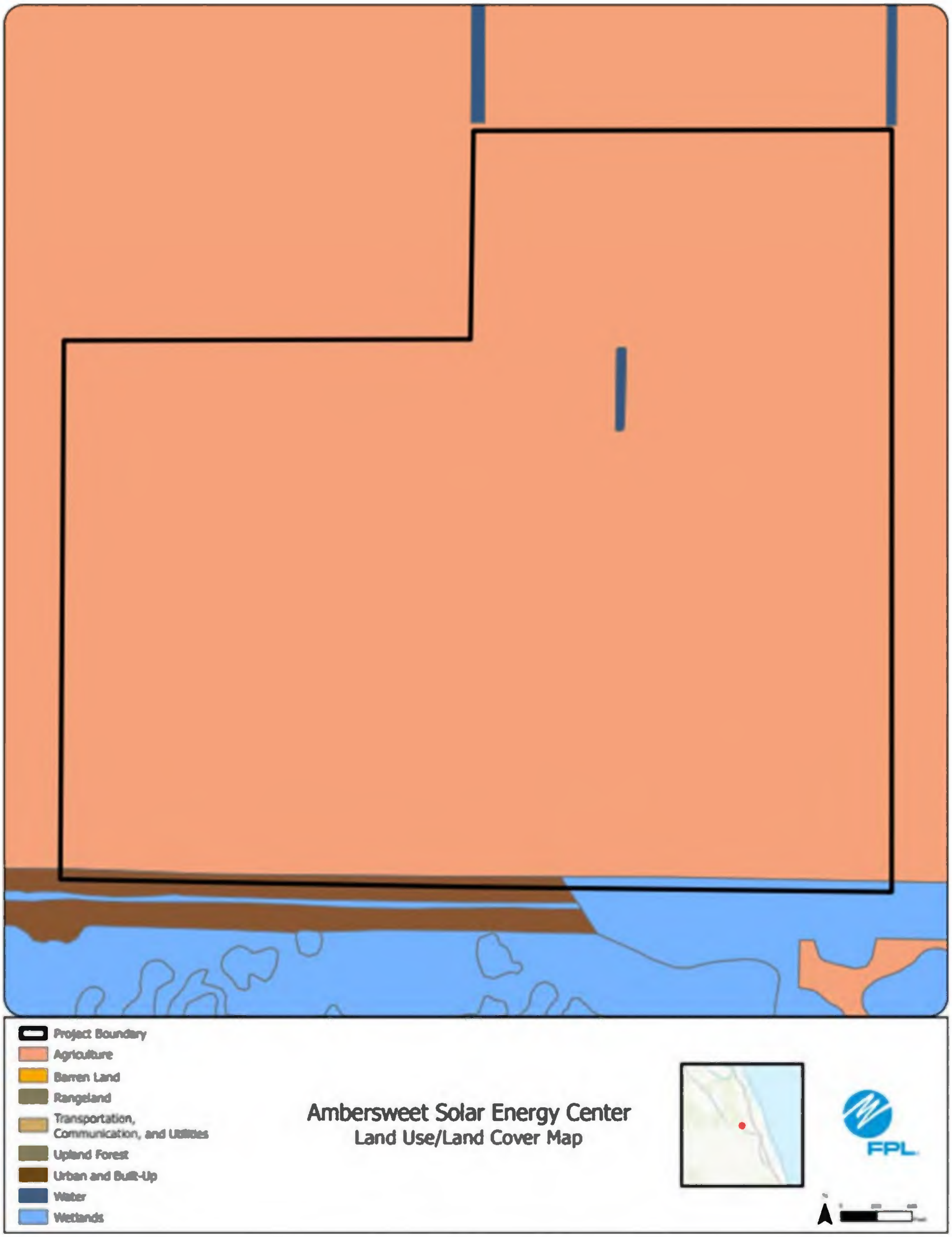
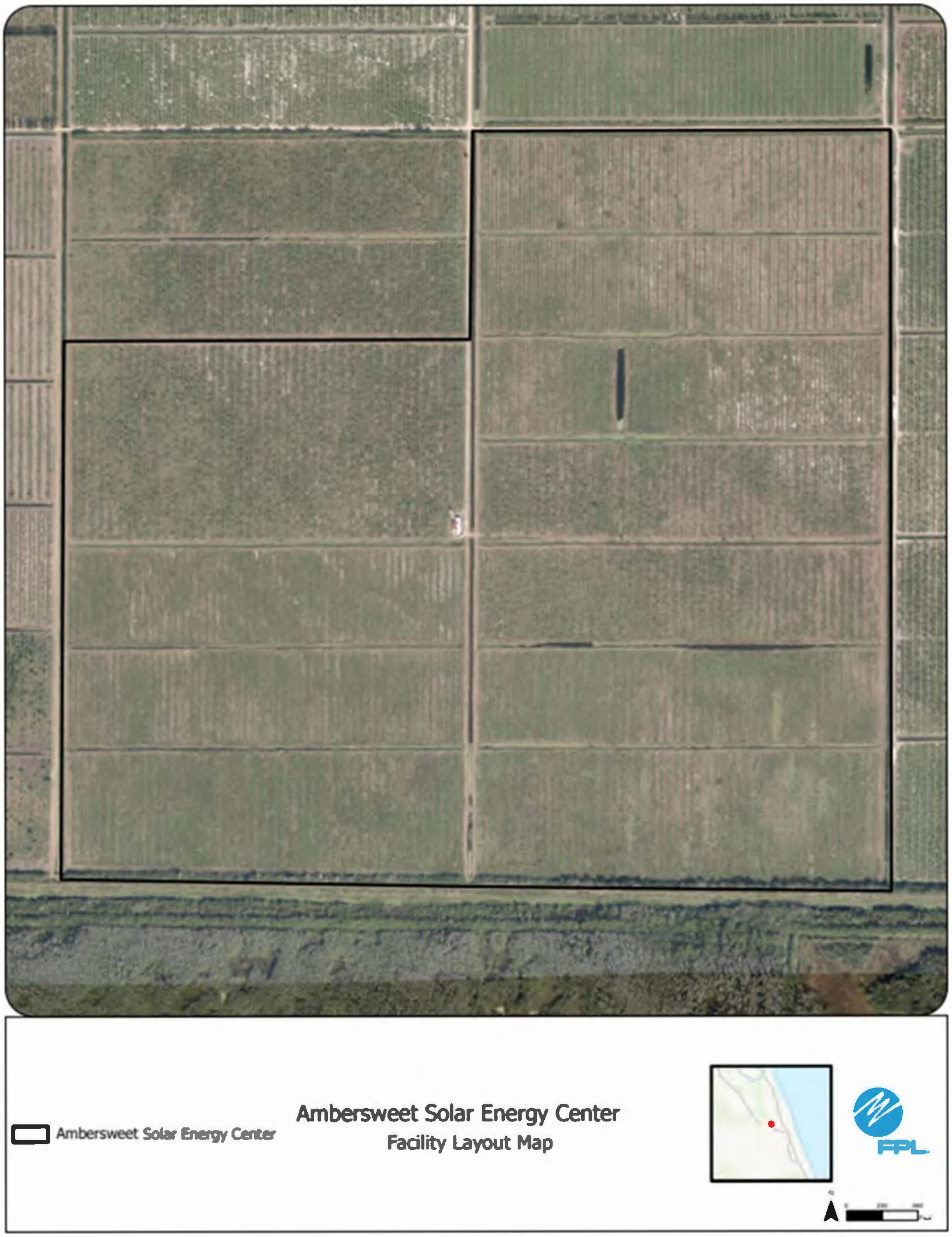
CO
Ambersweet Solar Energy Center
Ambersweet Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Ambersweet Solar Energy Center
Land Use/Land Cover Map
FPL


Ambersweet Solar Energy Center
Ambersweet Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #19: County Line Solar Energy Center, Charlotte/DeSoto County

	Preferred Site	County Line Solar Energy Center
	County	DeSoto/Charlotte
	Facility Acreage	630
	COD	4/30/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Citrus and pasture
	Adjacent Areas	Adjacent areas are primarily citrus and other agricultural land
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is primarily citrus
2.	Listed Species	Gopher tortoise and Audubon's crested caracara
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the Central region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 2/6/2024 FDEP 404 GP Issued: 2/6/2024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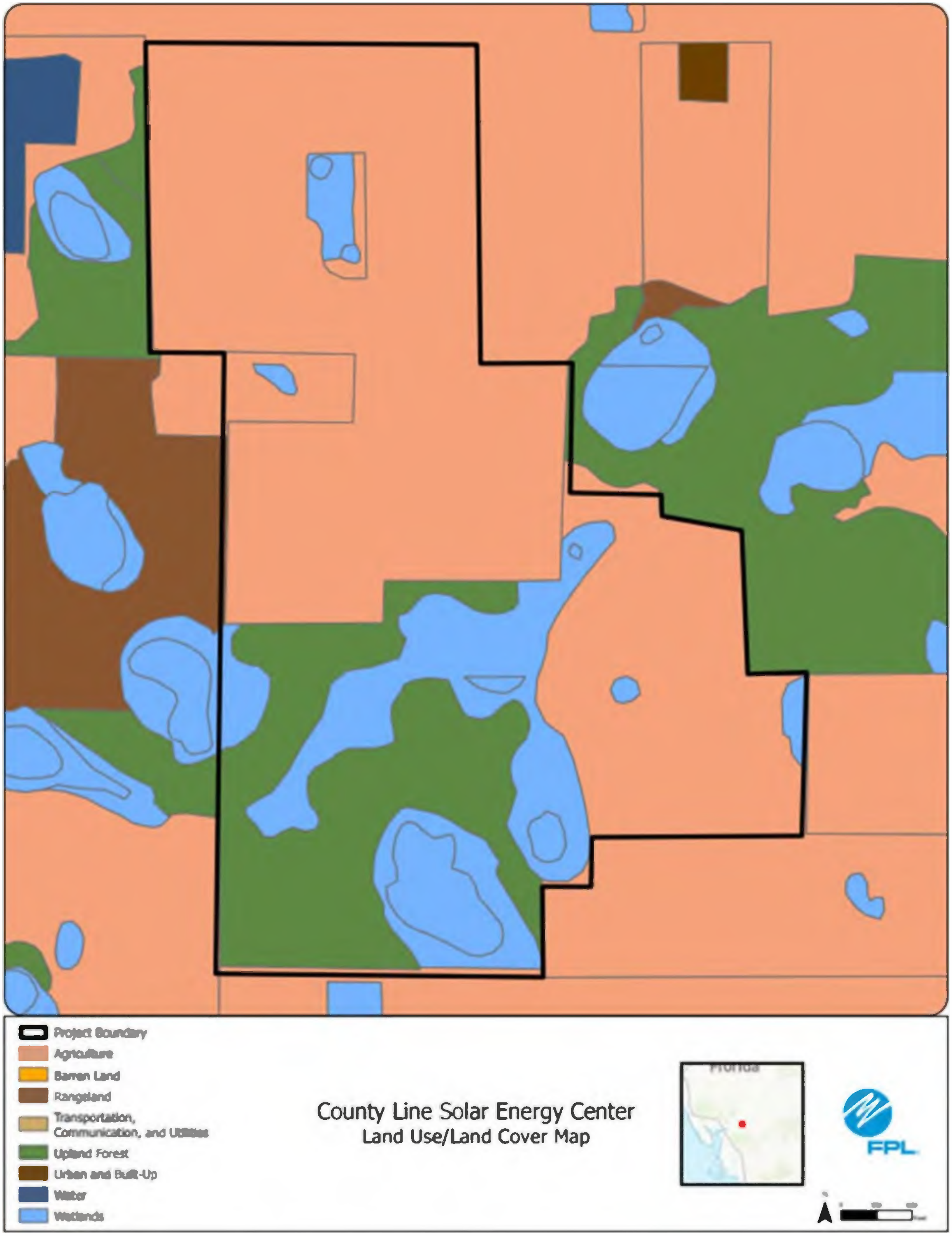
County Line Solar Energy Center
County Line Solar Energy Center
USGS Topography Map
FPL

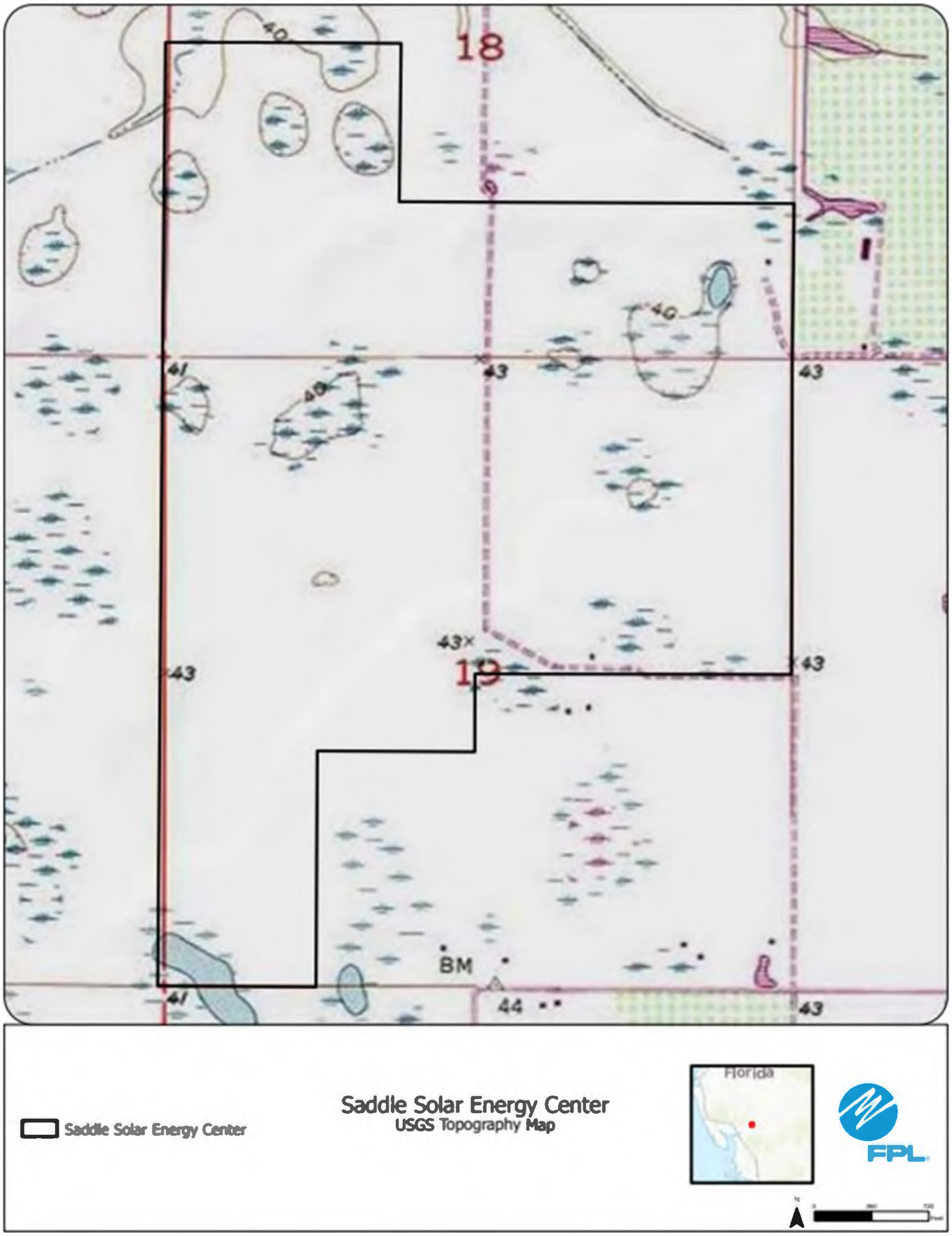

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
County Line Solar Energy Center
Land Use/Land Cover Map
FPL


County Line Solar Energy Center
County Line Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #20: Saddle Solar Energy Center, DeSoto County

	Preferred Site	Saddle Solar Energy Center
	County	DeSoto
	Facility Acreage	647
	COD	4/30/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Former citrus and row crops
	Adjacent Areas	Agricultural lands and low density residential
f.		General Environment Features On and In the Site Vicinity
1	Natural Environment	Site has been cleared of citrus and is currently open fields.
2	Listed Species	Audubon's crested caracara and Florida burrowing owls
3	Natural Resources of Regional Significance Status	Hawthorne Creek and Hog Bay are located just north of the project area.
4	Other Significant Features	FPL is not aware of any significant features nearby.
g.	Design Features and Mitigation Options	The design includes a approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the Central region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 2/29/2024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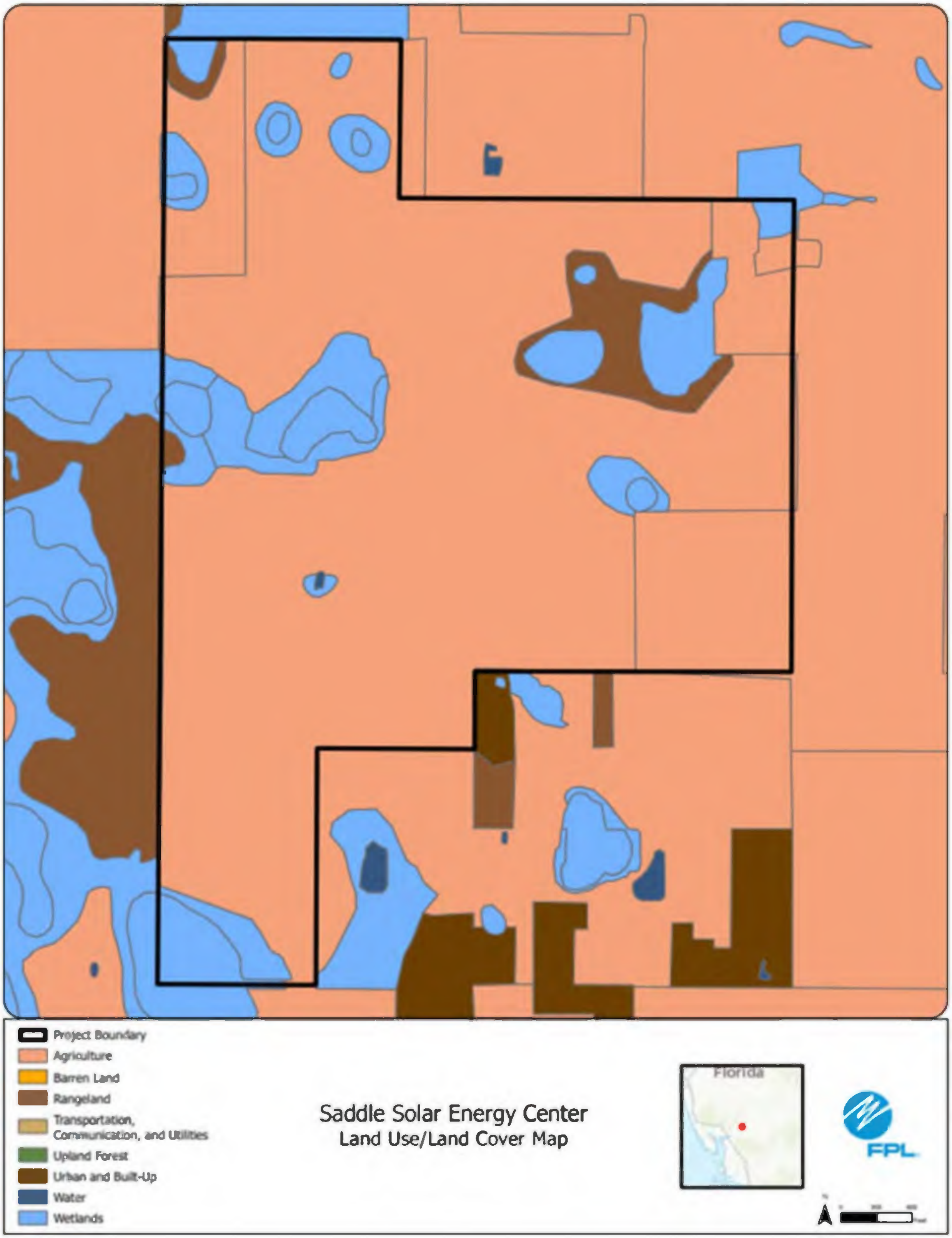
Saddle Solar Energy Center
Saddle Solar Energy Center
USGS Topography Map
Florida
FPL

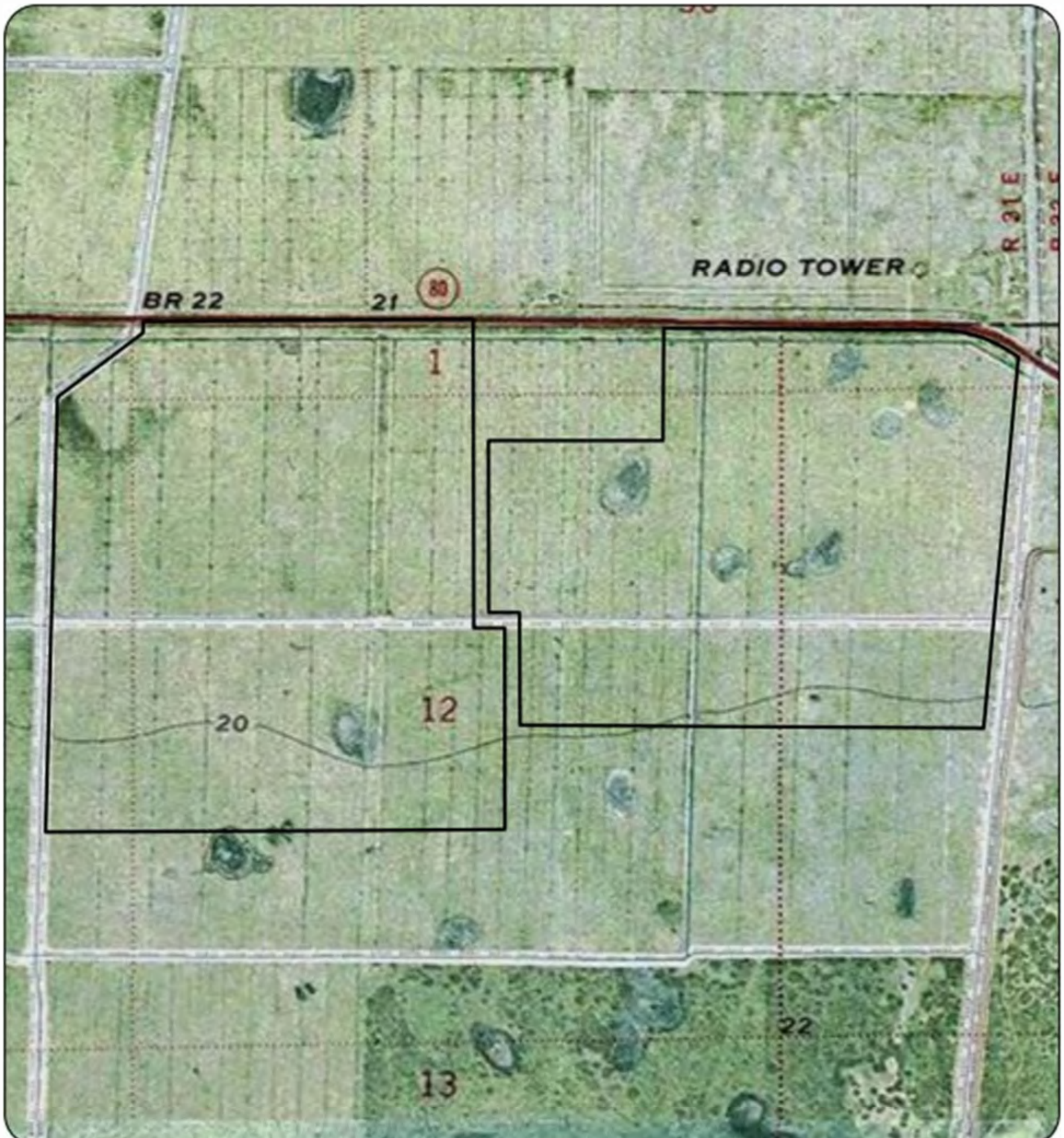

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Saddle Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Saddle Solar Energy Center
Saddle Solar Energy Center
Facility Layout Map
Florida
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

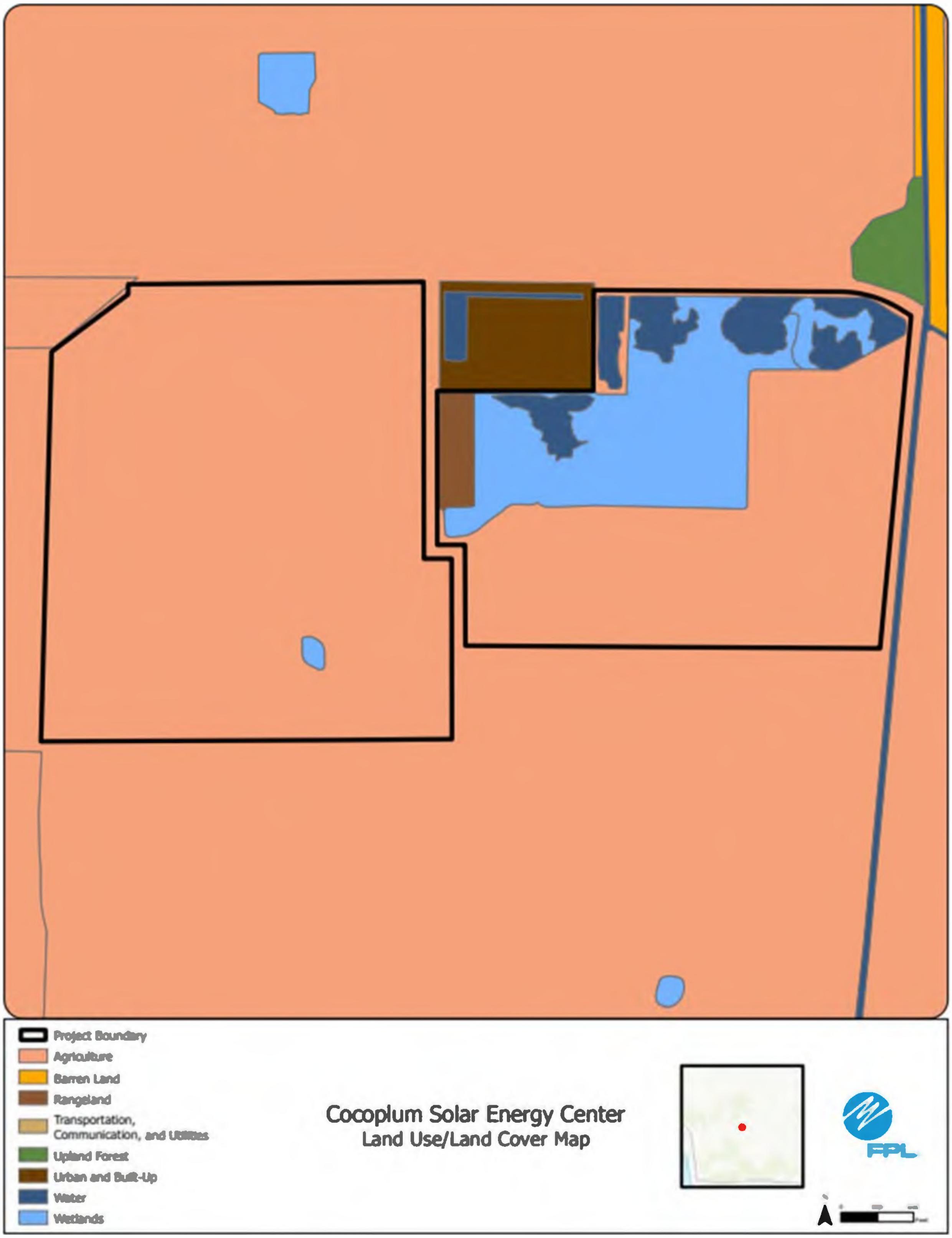
Preferred Site #21: Cocoplum Solar Energy Center, Hendry County

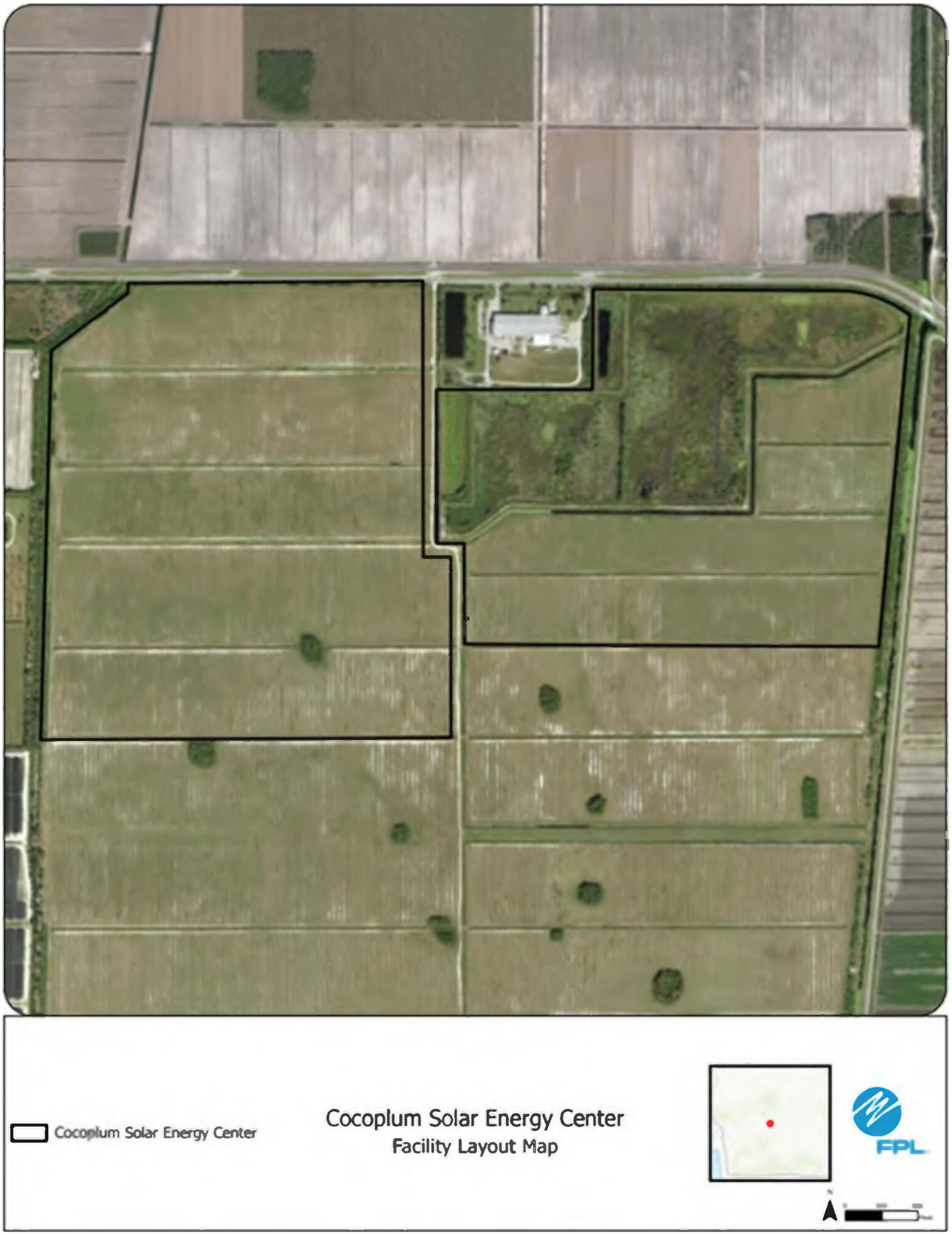
	Preferred Site	Cocoplum Solar Energy Center
	County	Hendry
	Facility Acreage	1665 (470 project acres)
	COD	7/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Agricultural pasture, agricultural ditches, and wetlands
	Adjacent Areas	Various agriculture, above ground impoundment, and SR80
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	The entire property consists of improved pasture with agricultural diches and some natural wetlands.
2.	Listed Species	Audubon's crested caracara, wading birds
3.	Natural Resources of Regional Significance Status	Large, aboveground impoundment located adjacent to site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP 404 NPR Issued: 9/14/2023 FDEP ERP Issued: 9/14/2023



Cocoplum Solar Energy Center

Cocoplum Solar Energy Center
USGS Topography Map

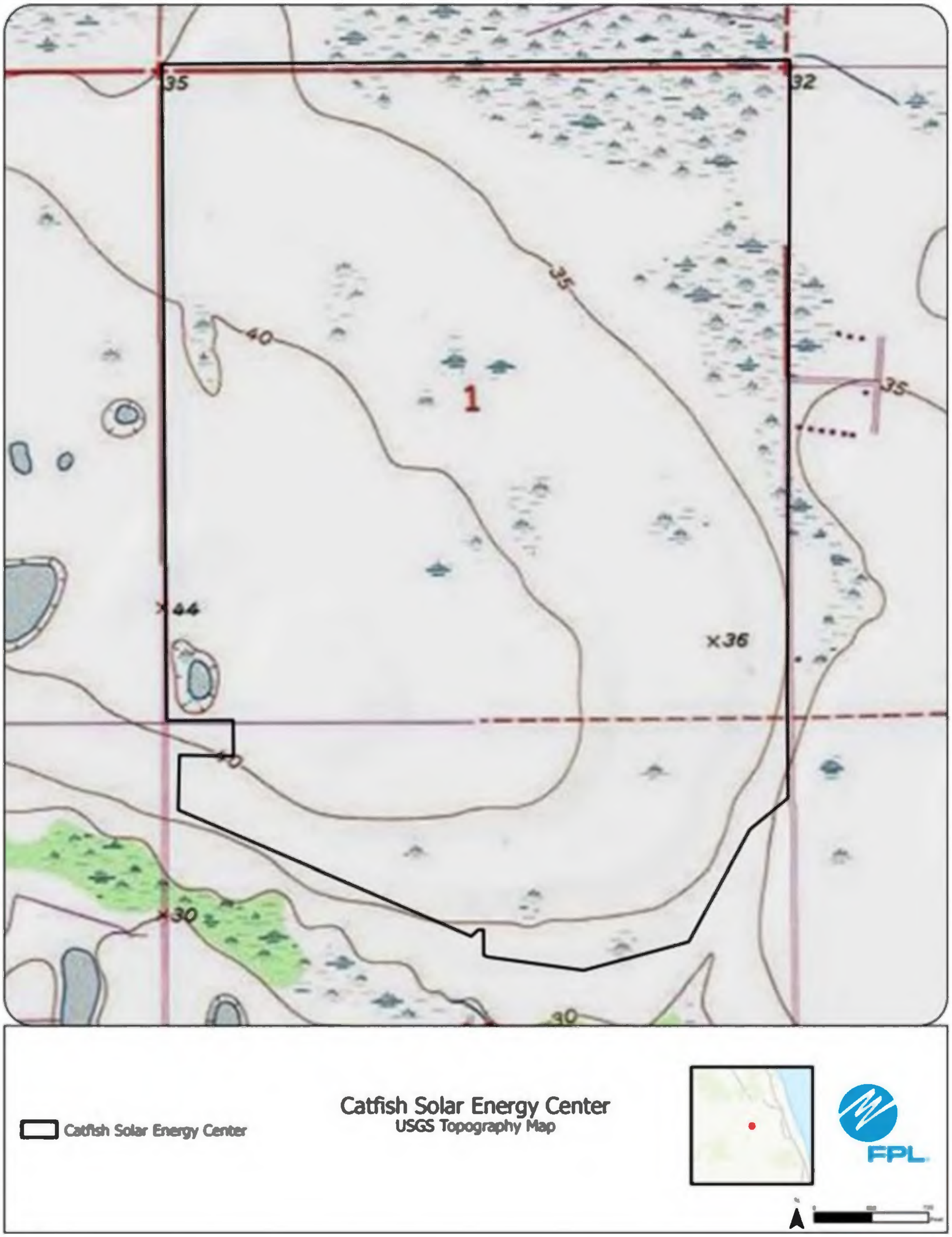

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Cocoplum Solar Energy Center
Land Use/Land Cover Map
FPL


Cocoplum Solar Energy Center
Cocoplum Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #22: Catfish Solar Energy Center, Okeechobee County

	Preferred Site	Catfish Solar Energy Center
	County	Okeechobee
	Facility Acreage	1525 (837 project acres)
	COD	7/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Predominantly improved pasture and woodland pasture
	Adjacent Areas	Solar, residential
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Site is improved pasture with some interspersed forested and herbaceous wetlands.
2.	Listed Species	Gopher tortoise, Audubon's crested caracara, Florida burrowing owl
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	Historic Evergreen Cemetery located just NW of project area.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.)
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 11/27/2023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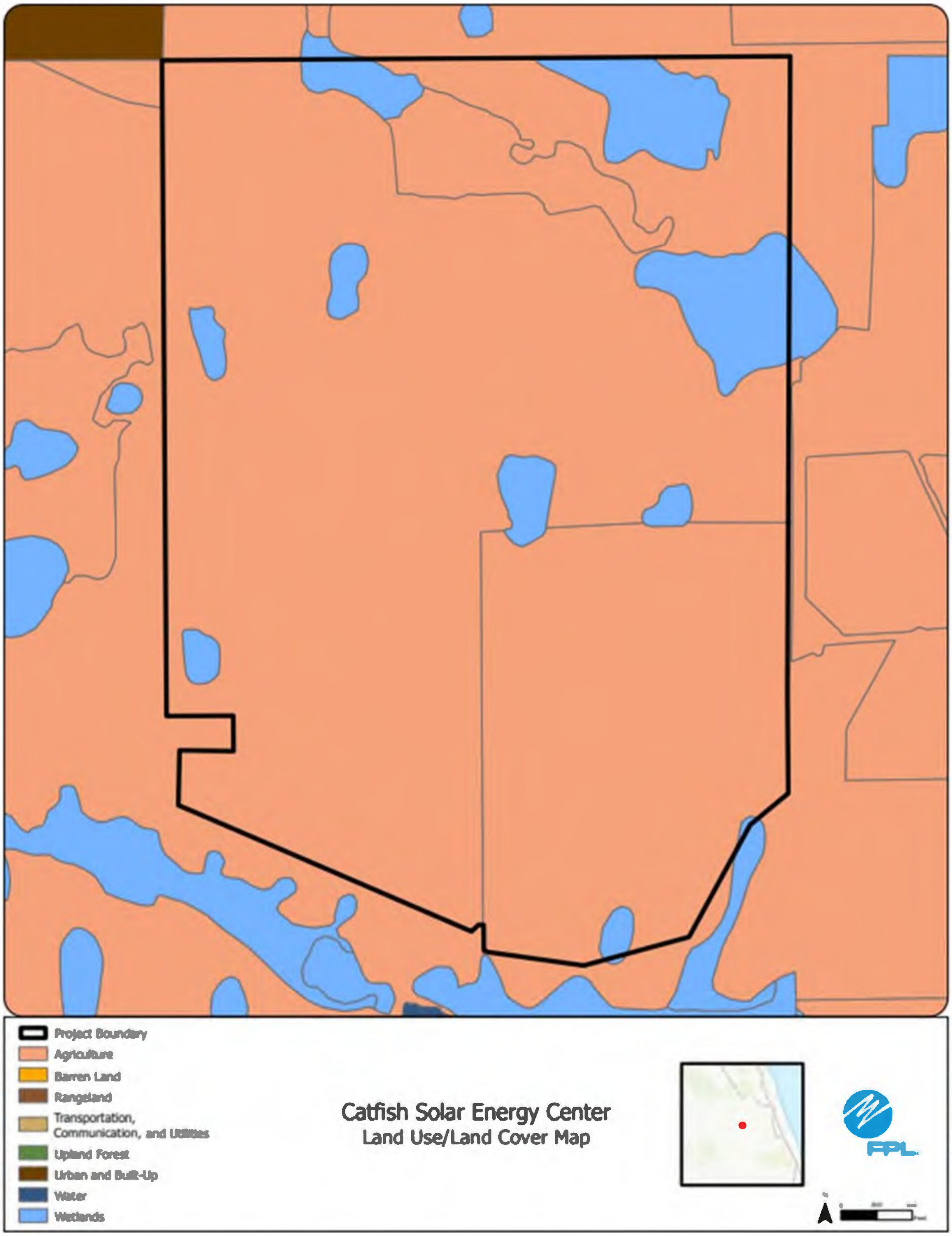
Catfish Solar Energy Center
Catfish Solar Energy Center
USGS Topography Map
FPL

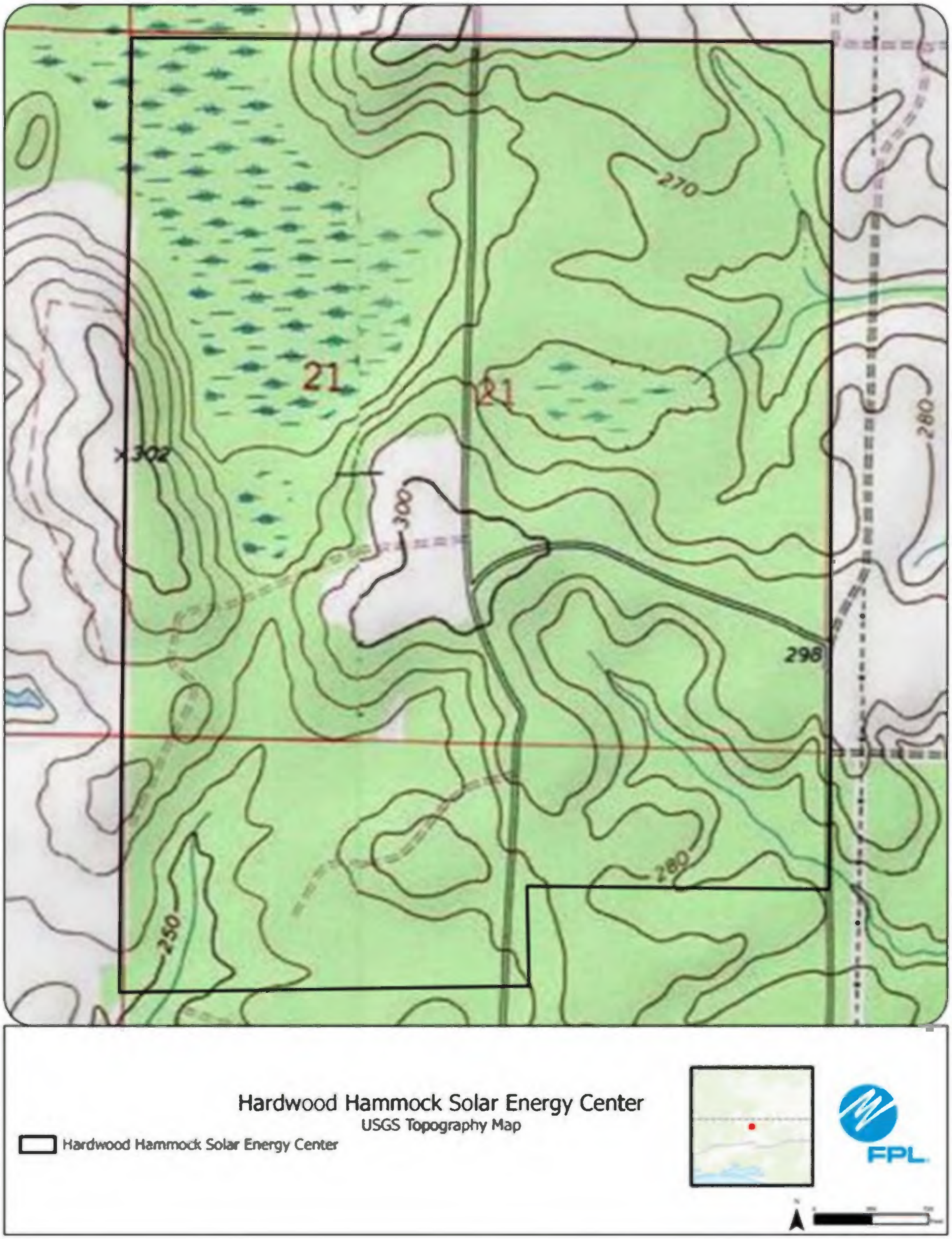

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Catfish Solar Energy Center
Land Use/Land Cover Map
FPL


Catfish Solar Energy Center
Catfish Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #23: Hardwood Hammock Solar Energy Center, Walton County

	Preferred Site	Hardwood Hammock Solar Energy Center
	County	Walton
	Facility Acreage	750
	COD	7/31/2027
	For PV facilities: tracking or fixed	Tracking
	Reference Maps	
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.	**Existing Land Uses**	
	Site	Pine and wetlands
	Adjacent Areas	Primarily pine
f.	**General Environment Features On and In the Site Vicinity**	
1.	Natural Environment	Site is primarily pine and wetlands.
2.	Listed Species	Gopher tortoise
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figures in the following pages. Site located in the Panhandle region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel, therefore there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 5/10/24 USACE 404 Issued: 9/25/24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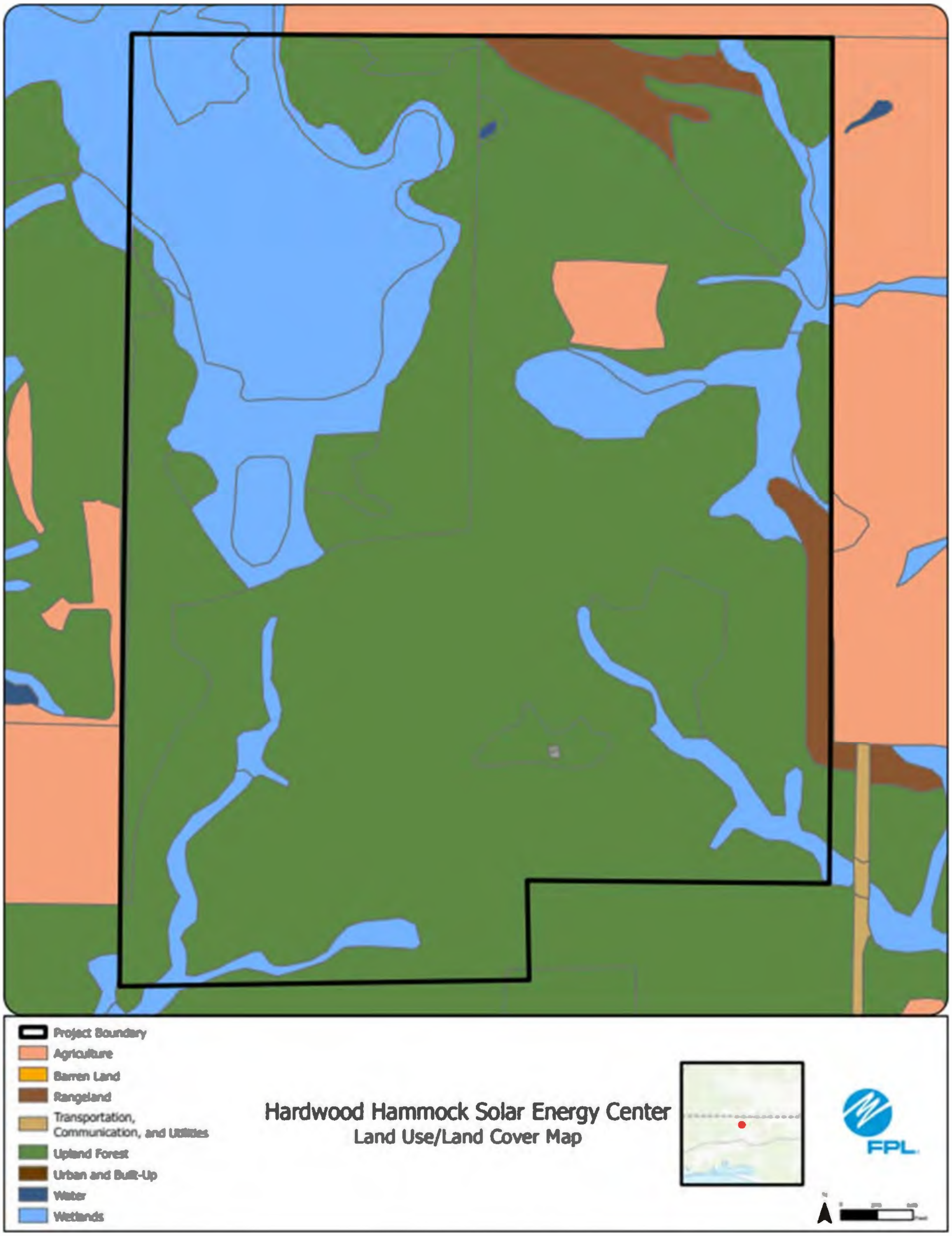
Hardwood Hammock Solar Energy Center
USGS Topography Map
Hardwood Hammock Solar Energy Center
FPL

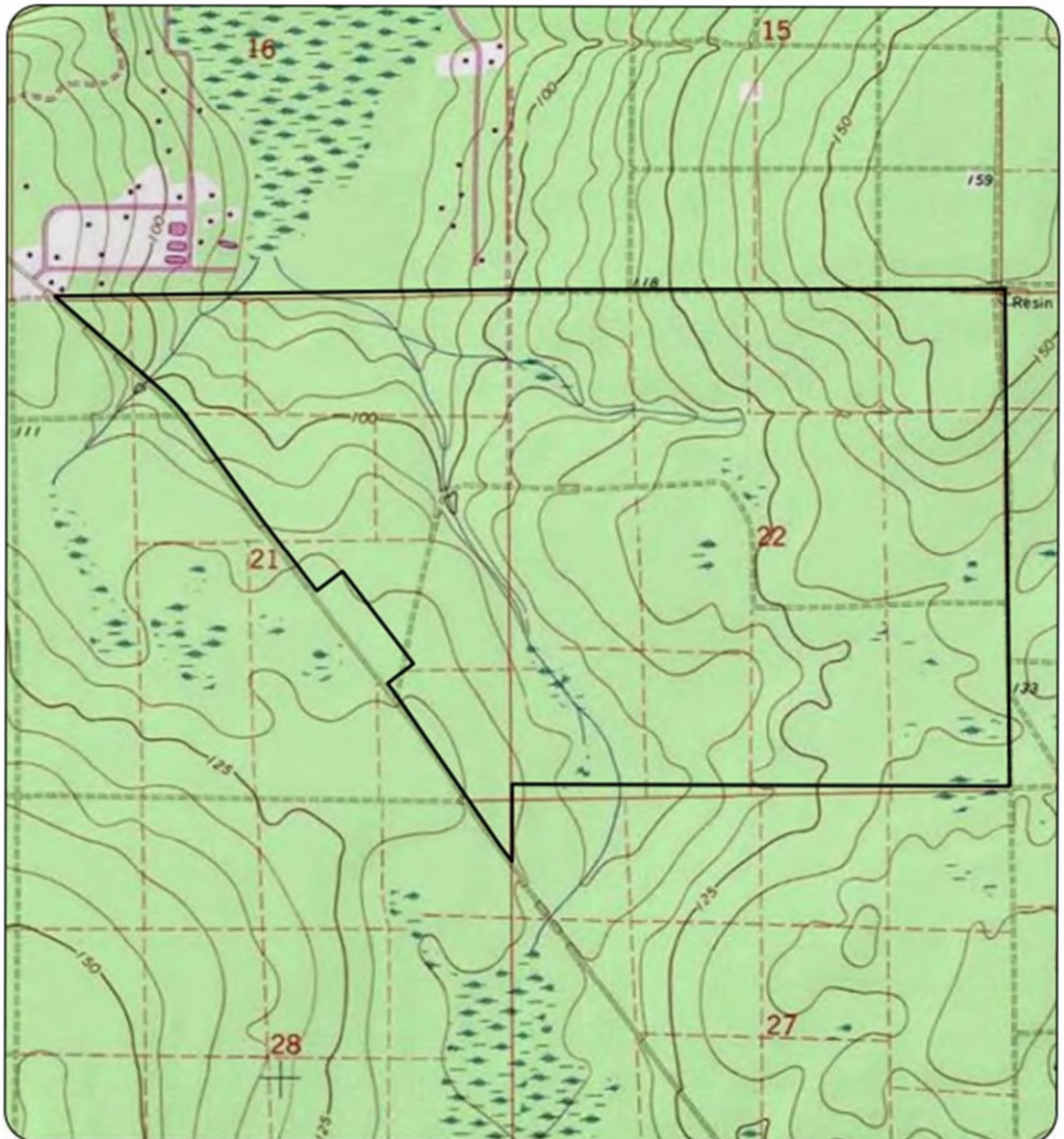

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Hardwood Hammock Solar Energy Center
Land Use/Land Cover Map
FPL


Hardwood Hammock Solar Energy Center
Facility Layout Map
Hardwood Hammock Solar Energy Center
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

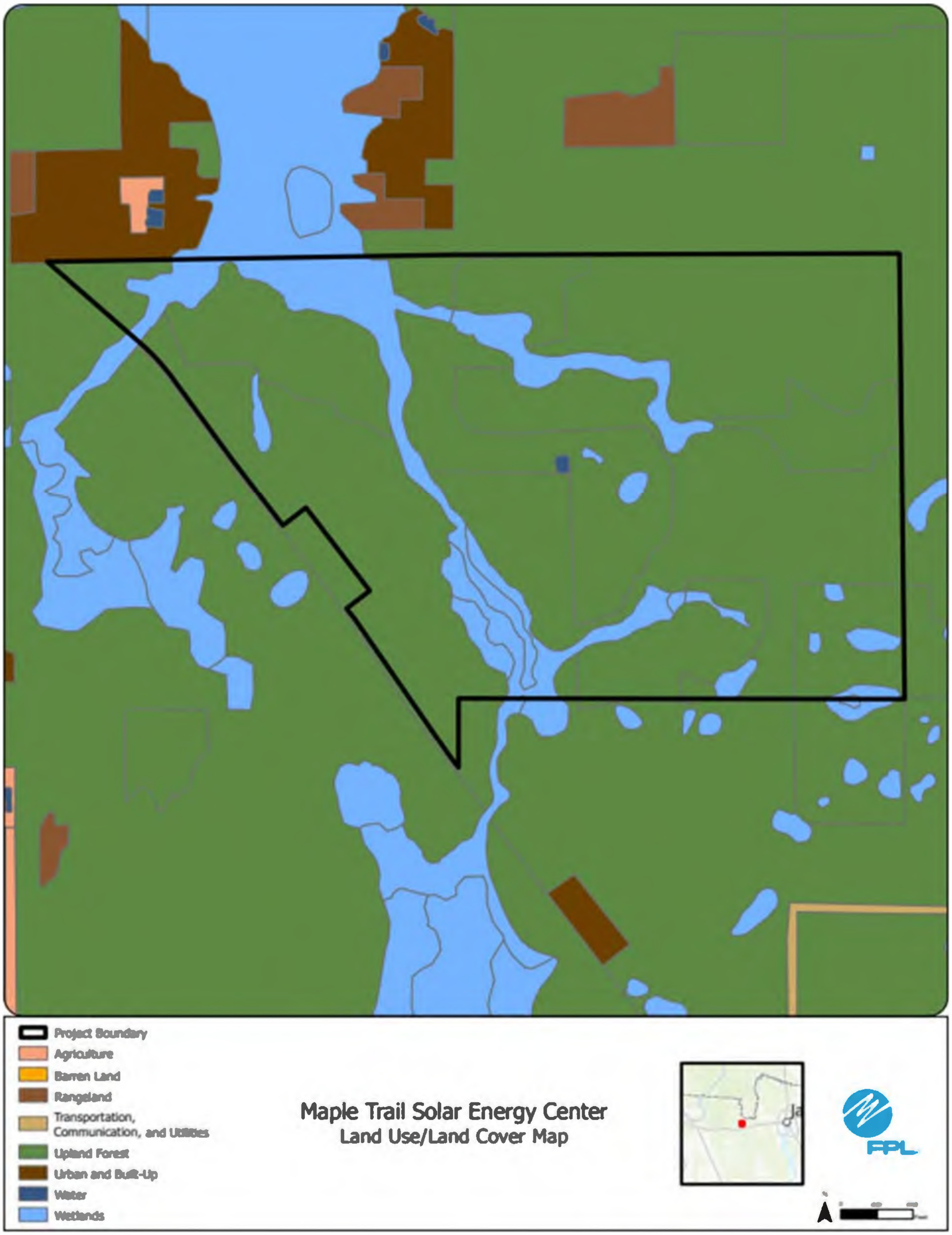
Preferred Site #24: Maple Trail Solar Energy Center, Baker County

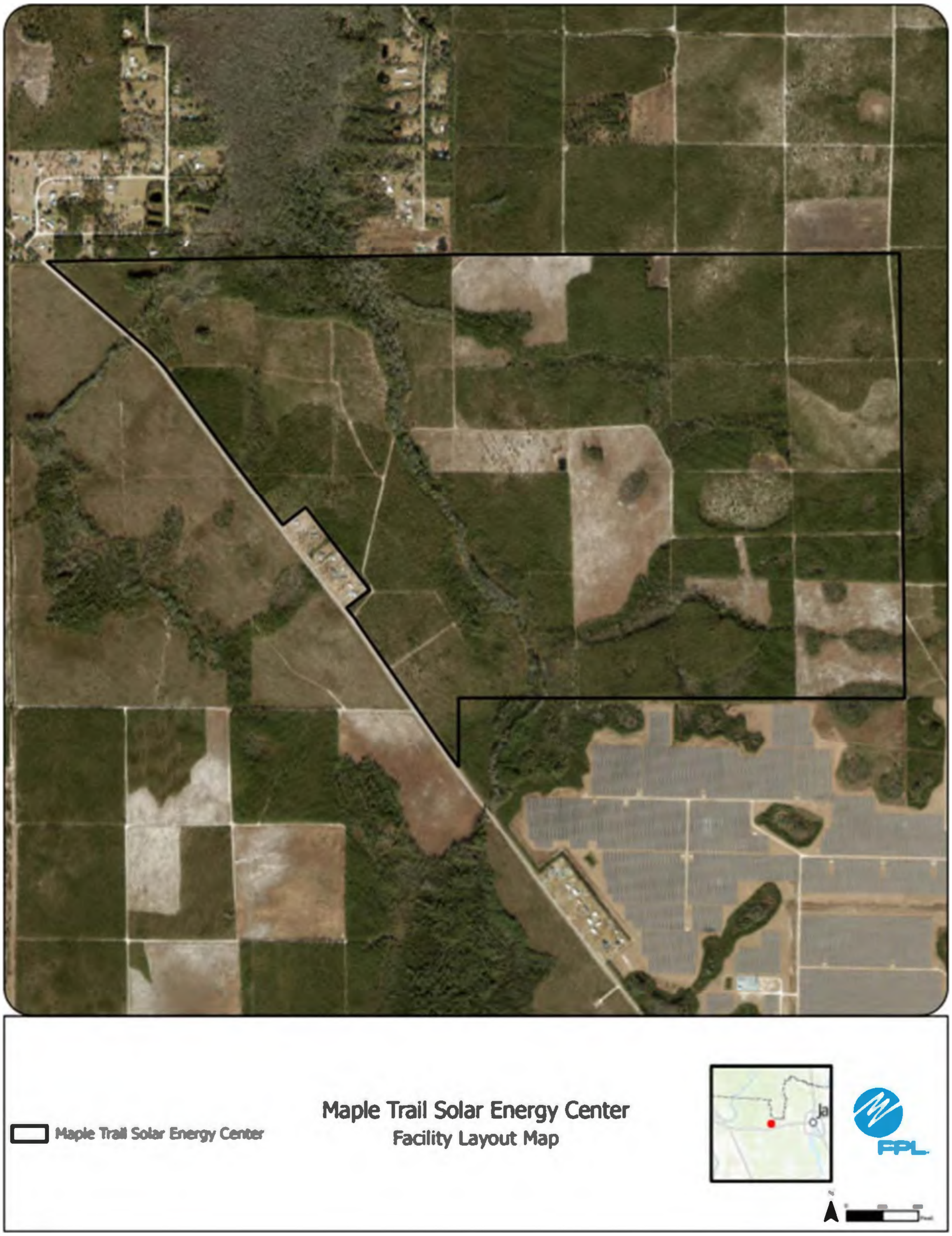
	Preferred Site	Maple Trail Solar Energy Center
	County	Baker
	Facility Acreage	2430 (930 project acres)
	COD	7/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Silviculture, other surface waters, natural wetlands, and a creek system
	Adjacent Areas	Residential, silviculture, wetlands, solar energy center
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	The site is dominated by silviculture with a natural creek system, wetlands, and other surface waters also present on site.
2.	Listed Species	Gopher tortoise
3.	Natural Resources of Regional Significance Status	Natural creek running through the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figures in the following page. Site is located in the Panhandle region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 9/3/2024 USACE 404 Permit Issued: 1/28/2025



Maple Trail Solar Energy Center
USGS Topography Map

Maple Trail Solar Energy Center

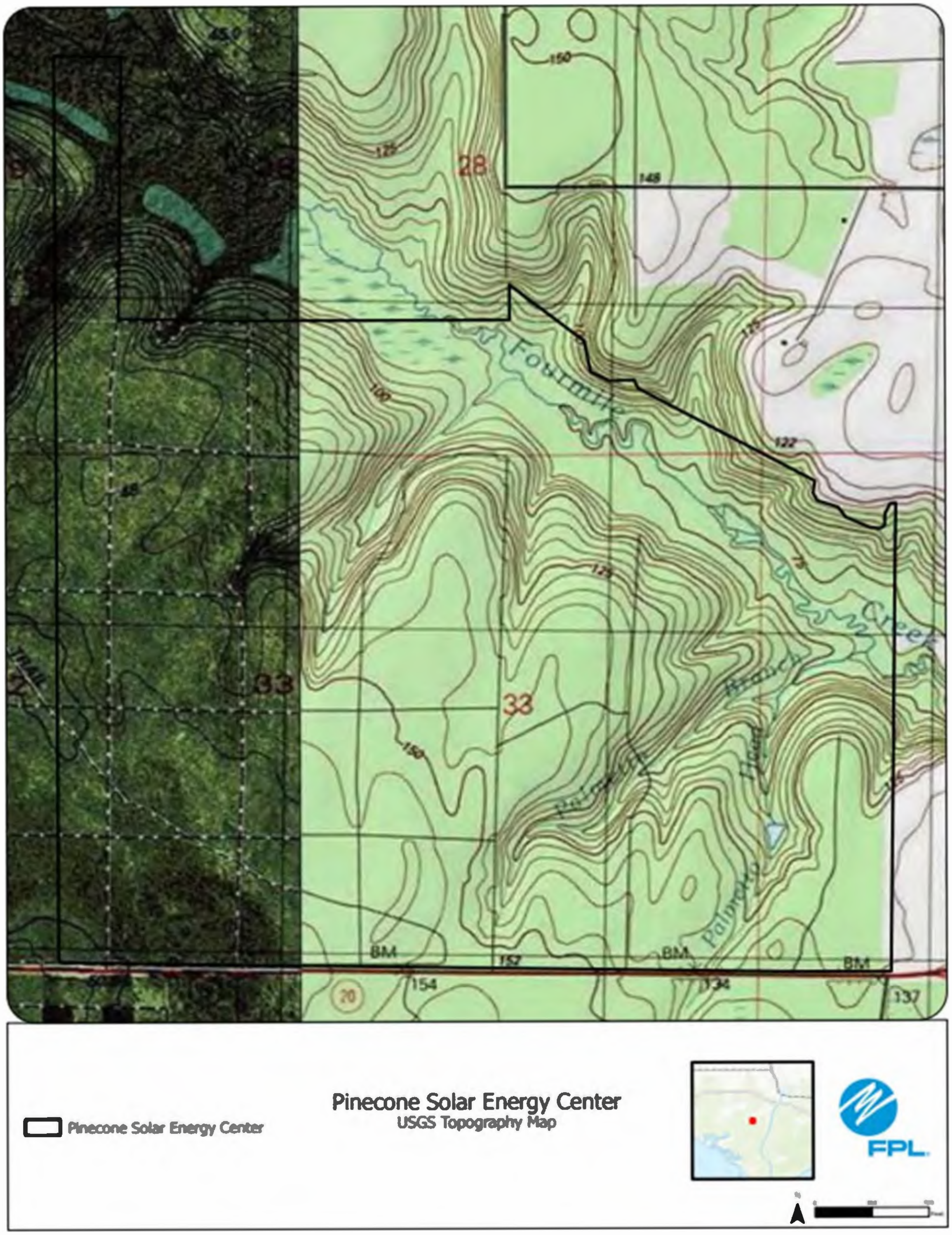

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Maple Trail Solar Energy Center
Land Use/Land Cover Map
FPL


Maple Trail Solar Energy Center
Maple Trail Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #25: Pinecone Solar Energy Center, Calhoun County

	Preferred Site	Pinecone Solar Energy Center
	County	Calhoun
	Facility Acreage	1220.29 (438 project area)
	COD	10/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Silviculture, hunting
	Adjacent Areas	Timber, croplands, horse farms
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Site is primarily silviculture with some forested wetlands
2.	Listed Species	Gopher tortoise, eastern indigo snake
3.	Natural Resources of Regional Significance Status	Chipola Experimental Forest and Juniper Creek Wildlife Management Area to South of property.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the Panhandle region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 2/3/2025


Pinecone Solar Energy Center
Pinecone Solar Energy Center
USGS Topography Map
FPL
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Fourmile
Creek
Branch
BM
BM
BM
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137
150
125
100
122
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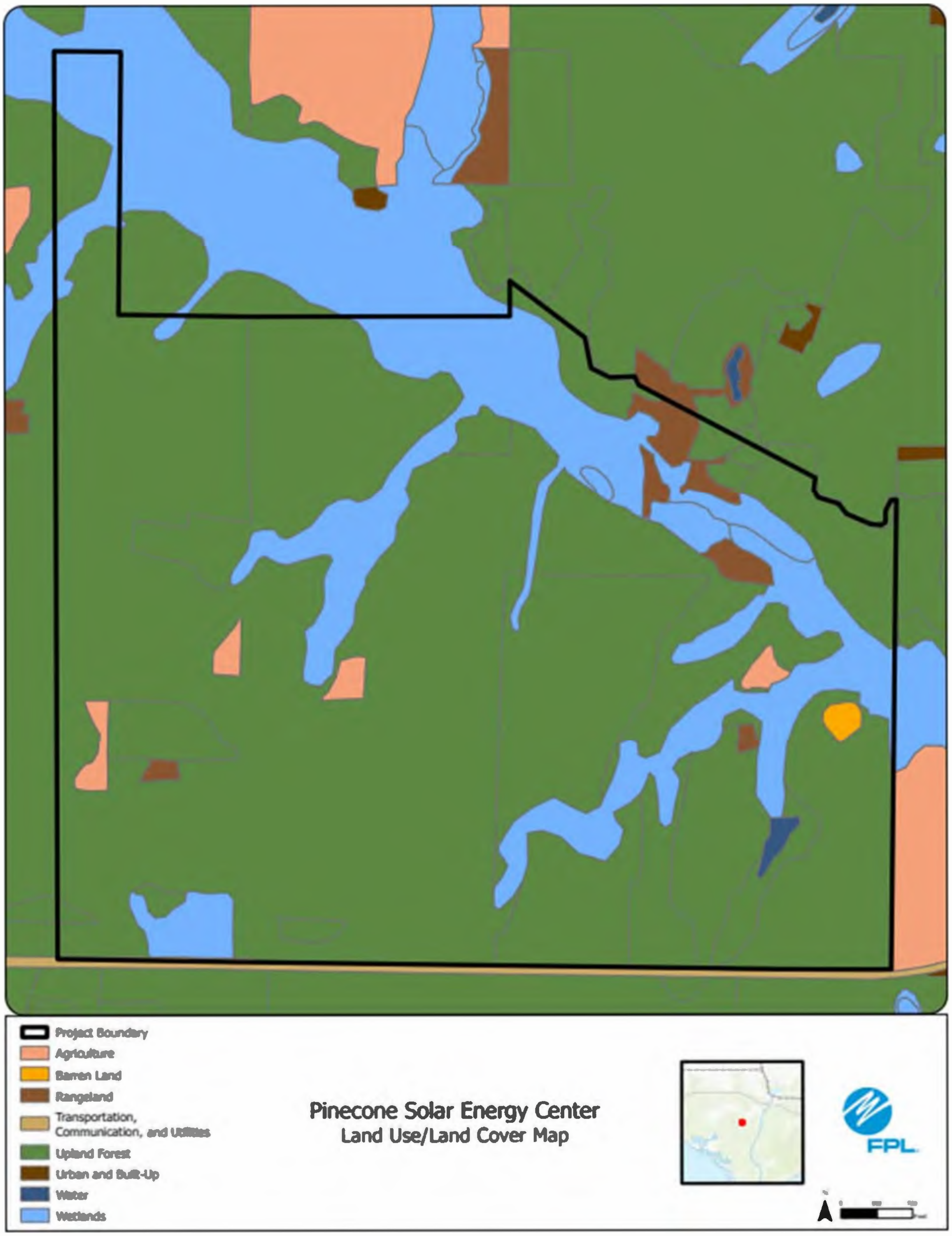
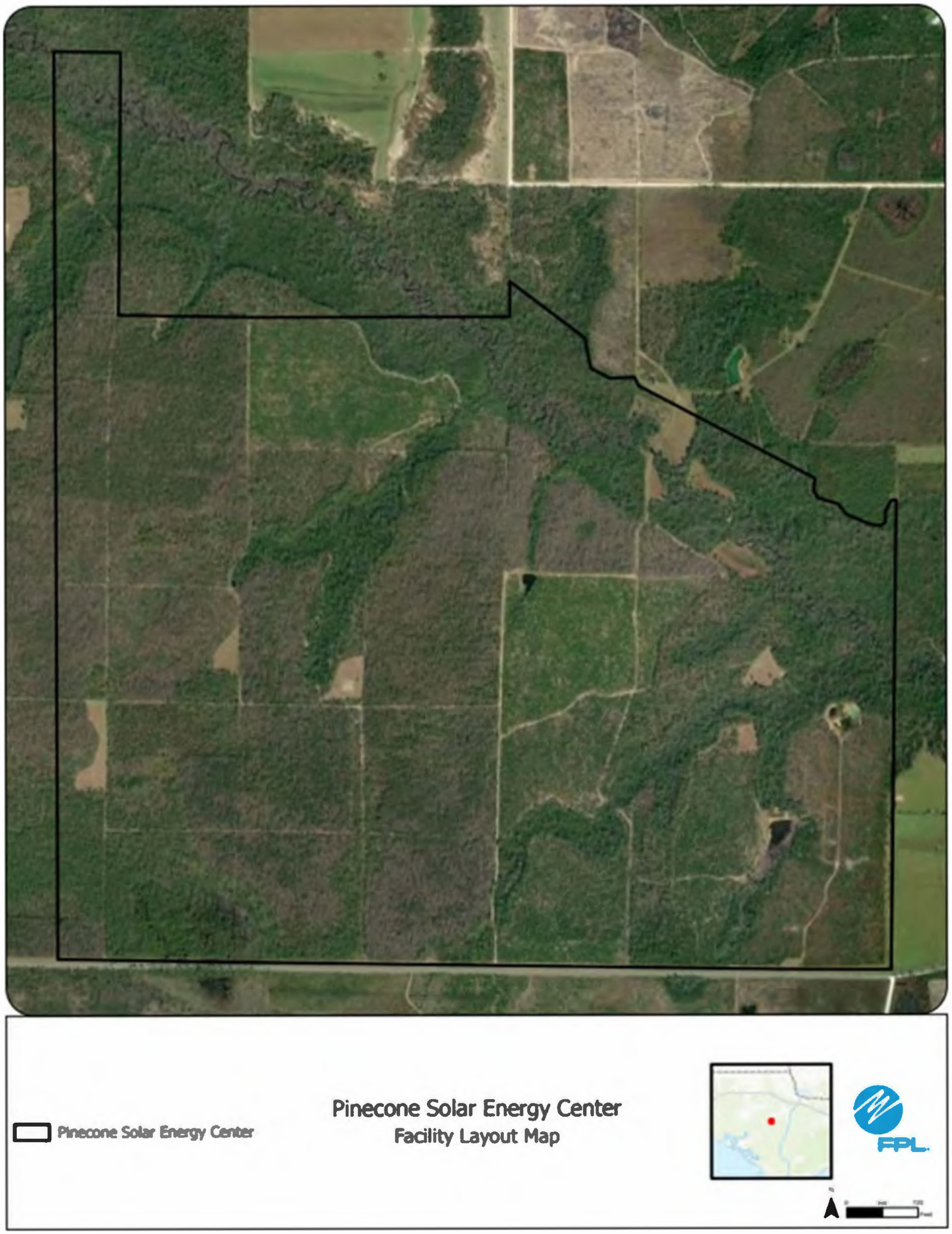
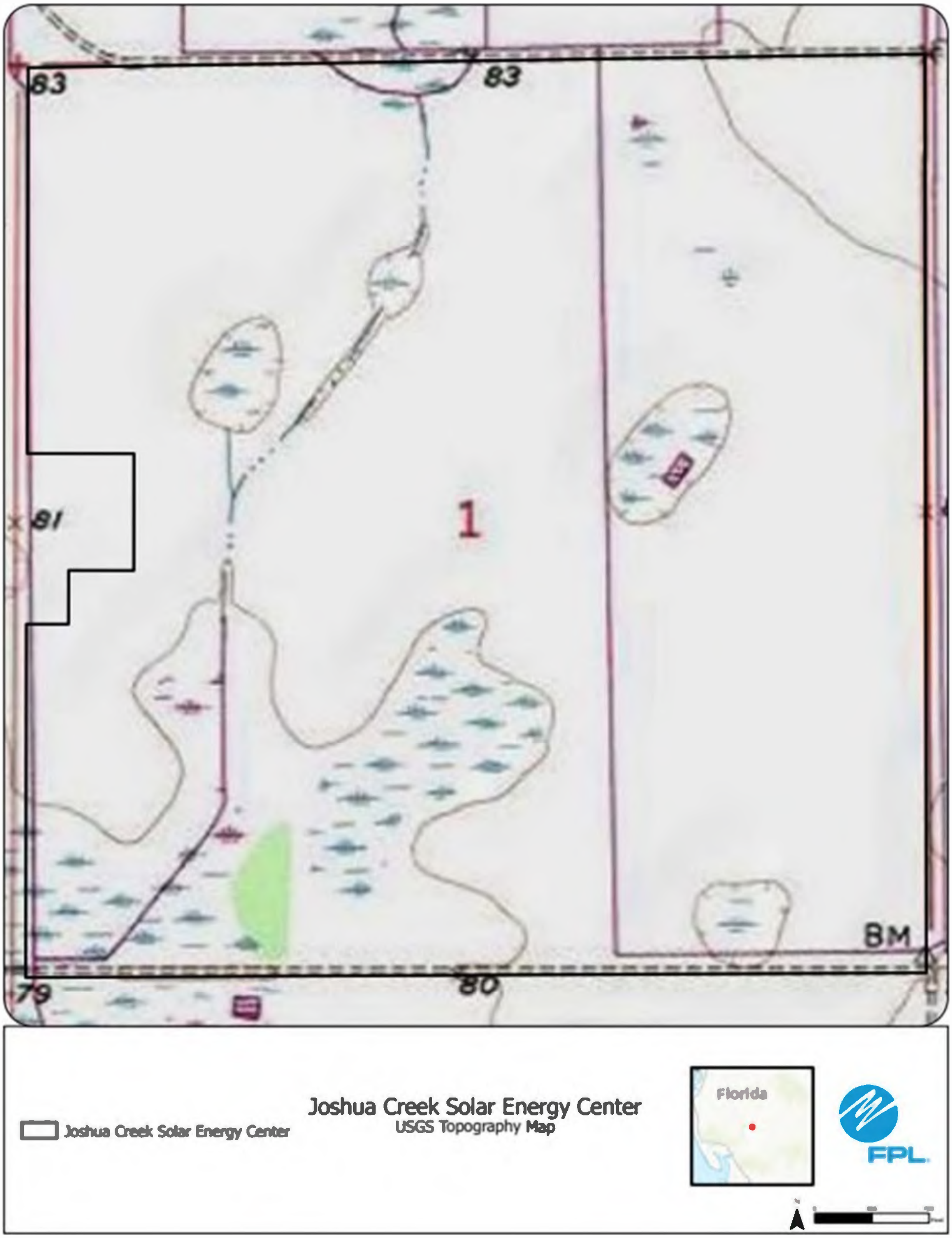

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Pinecone Solar Energy Center
Land Use/Land Cover Map
FPL


Pinecone Solar Energy Center
Pinecone Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #26: Joshua Creek Solar Energy Center, DeSoto County

	Preferred Site	Joshua Creek Solar Energy Center
	County	DeSoto
	Facility Acreage	621
	COD	10/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	**USGS Map**	See Figures in the following pages
b.	**Proposed Facilities Layout**	
c.	**Map of Site and Adjacent Areas**	
d.	**Land Use Map of site and Adjacent Areas**	
e.		**Existing Land Uses**
	Site	Row crops
	Adjacent Areas	Agricultural lands and low density residential
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Site is row crop fields with some wetland features around the property.
2	Listed Species	Audubon's crested caracara
3	Natural Resources of Regional Significance Status	Joshua Creek
4	Other Significant Features	FPL is not aware of any significant features nearby.
g.	**Design Features and Mitigation Options**	The design includes a approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	**Local Government Future Land Use Designations**	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	**Site Selection Criteria Factors**	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	**Water Resources**	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	**Geological Features of Site and Adjacent Areas**	See Figure in the following pages. Site is located in the Central region.
l.	**Project Water Quantities for Various Uses**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	**Water Supply Sources by Type**	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	**Water Conservation Strategies Under Consideration**	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	**Water Discharges and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	Solar does not require fuel and no waste products will be generated at the site
q.	**Air Emissions and Control Systems**	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	**Noise Emissions and Control Systems**	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	**Status of Applications**	FDEP ERP Issued: 4/24/2024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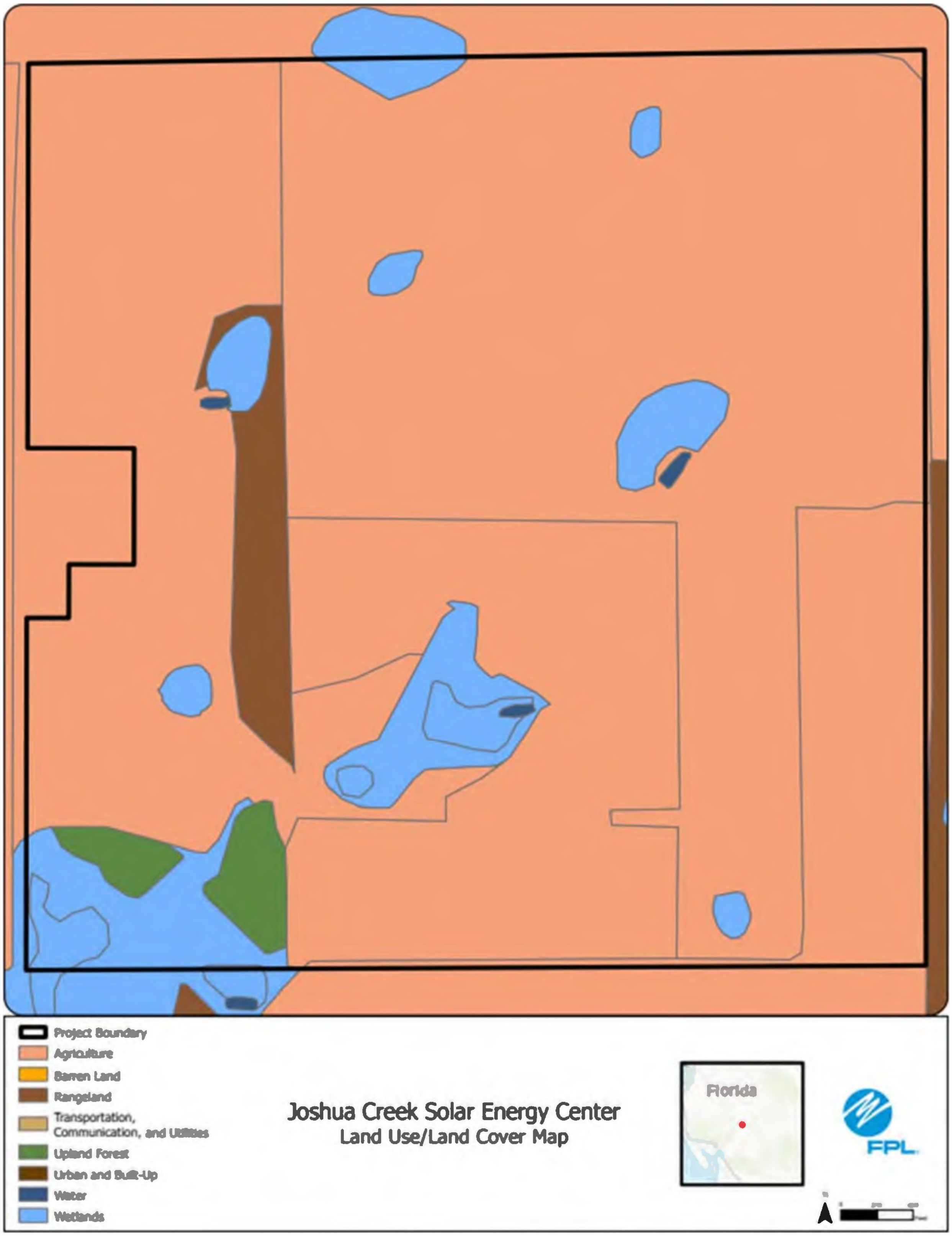
Joshua Creek Solar Energy Center
Joshua Creek Solar Energy Center
USGS Topography Map
Florida
FPL

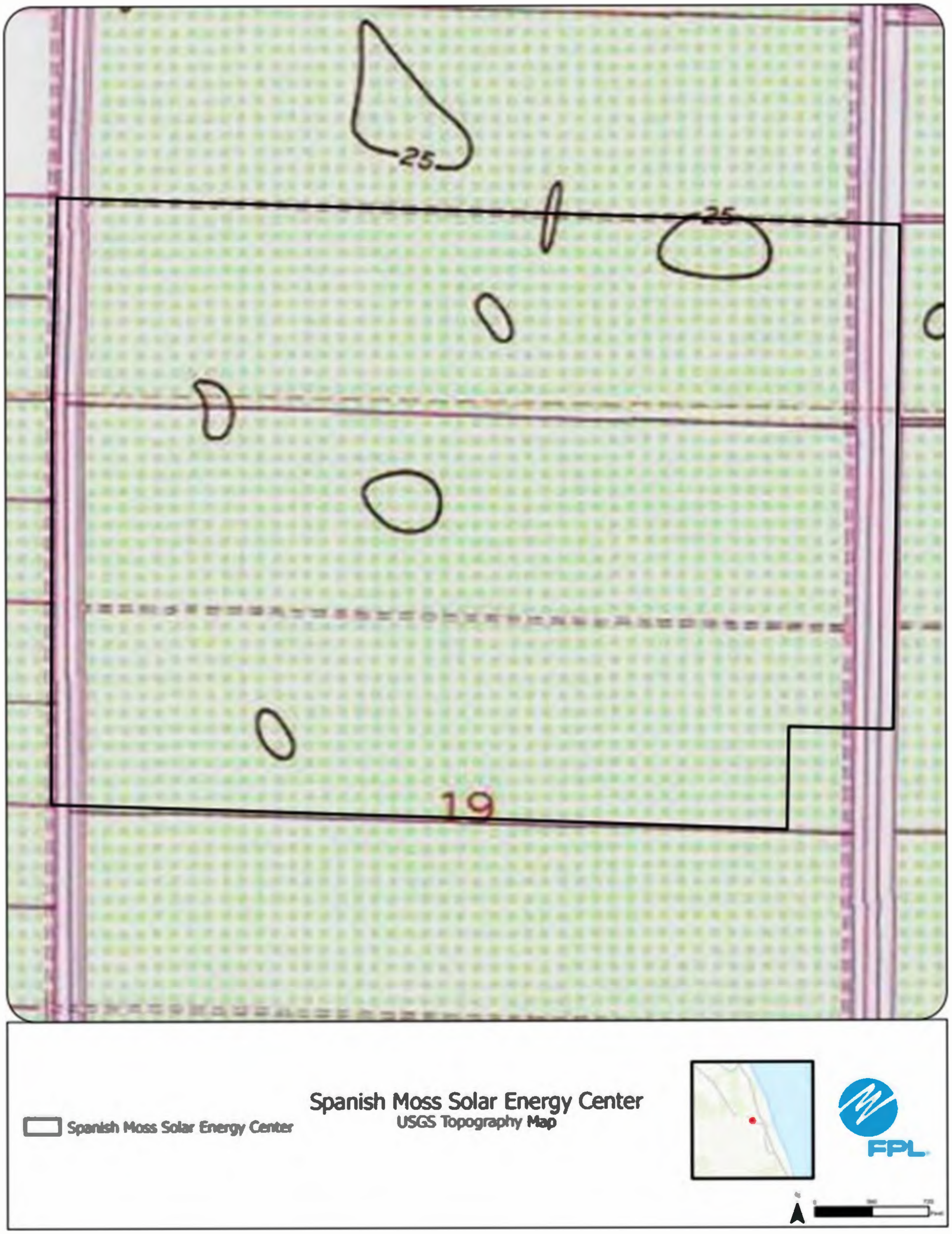

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Joshua Creek Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Joshua Creek Solar Energy Center
Joshua Creek Solar Energy Center
Facility Layout Map
Florida
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #27: Spanish Moss Solar Energy Center, St. Lucie County

	Potential Site	Spanish Moss Solar Energy Center
	County	St. Lucie
	Facility Acreage	2037 (483 project acres)
	COD	10/31/2027
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Improved pasture with agricultural ditches and wetlands
	Adjacent Areas	Various agriculture, ditches, and wetlands
f.		**General Environment Features On and In the Site Vicinity**
1	Natural Environment	Improved pasture with agricultural ditches and two small wetlands
2	Listed Species	Audubon's crested caracara, wading birds
3	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4	Other Significant Features	Formerly documented bald eagle nests to west of property
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP Issued: 3/13/24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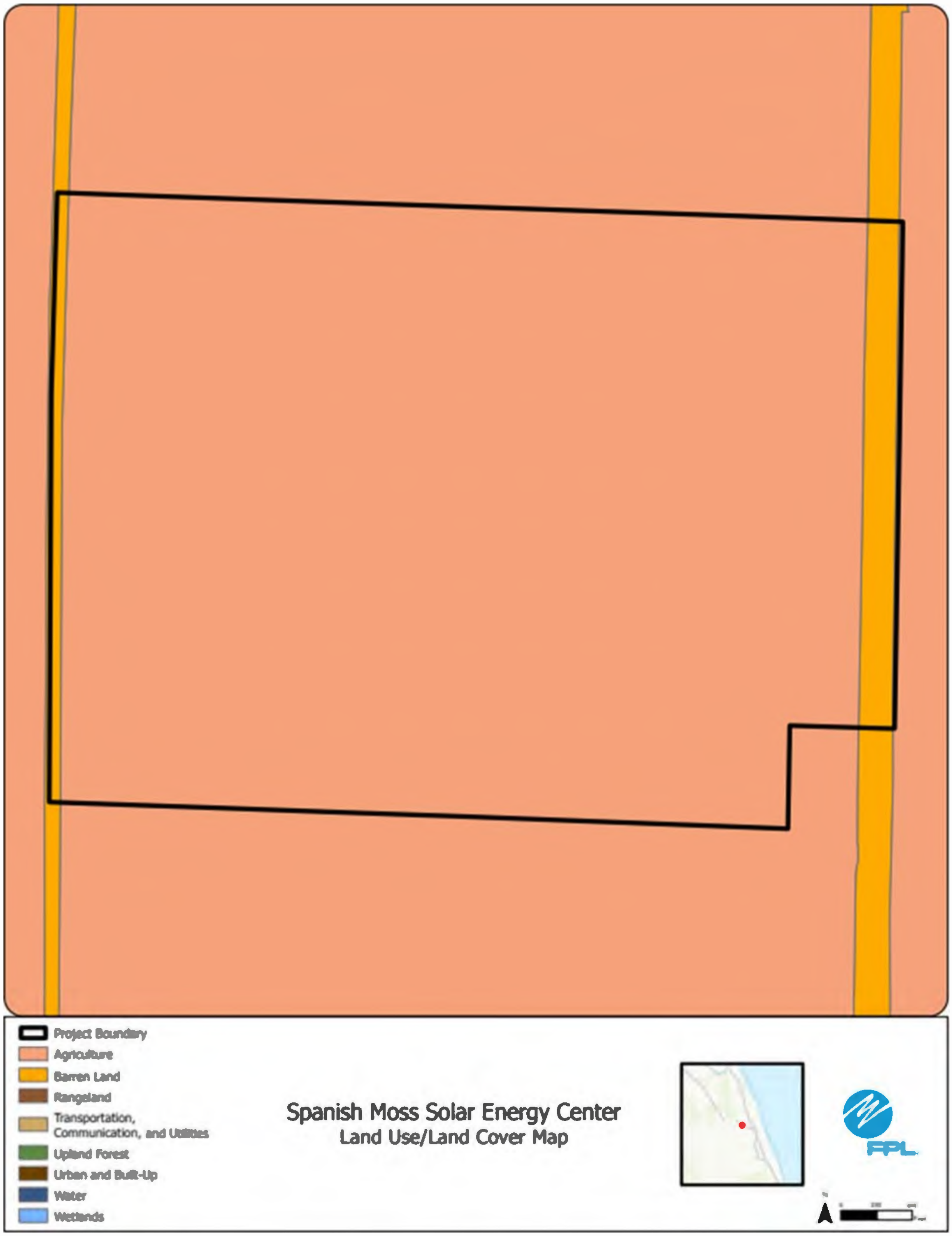
Spanish Moss Solar Energy Center
Spanish Moss Solar Energy Center
USGS Topography Map
FPL

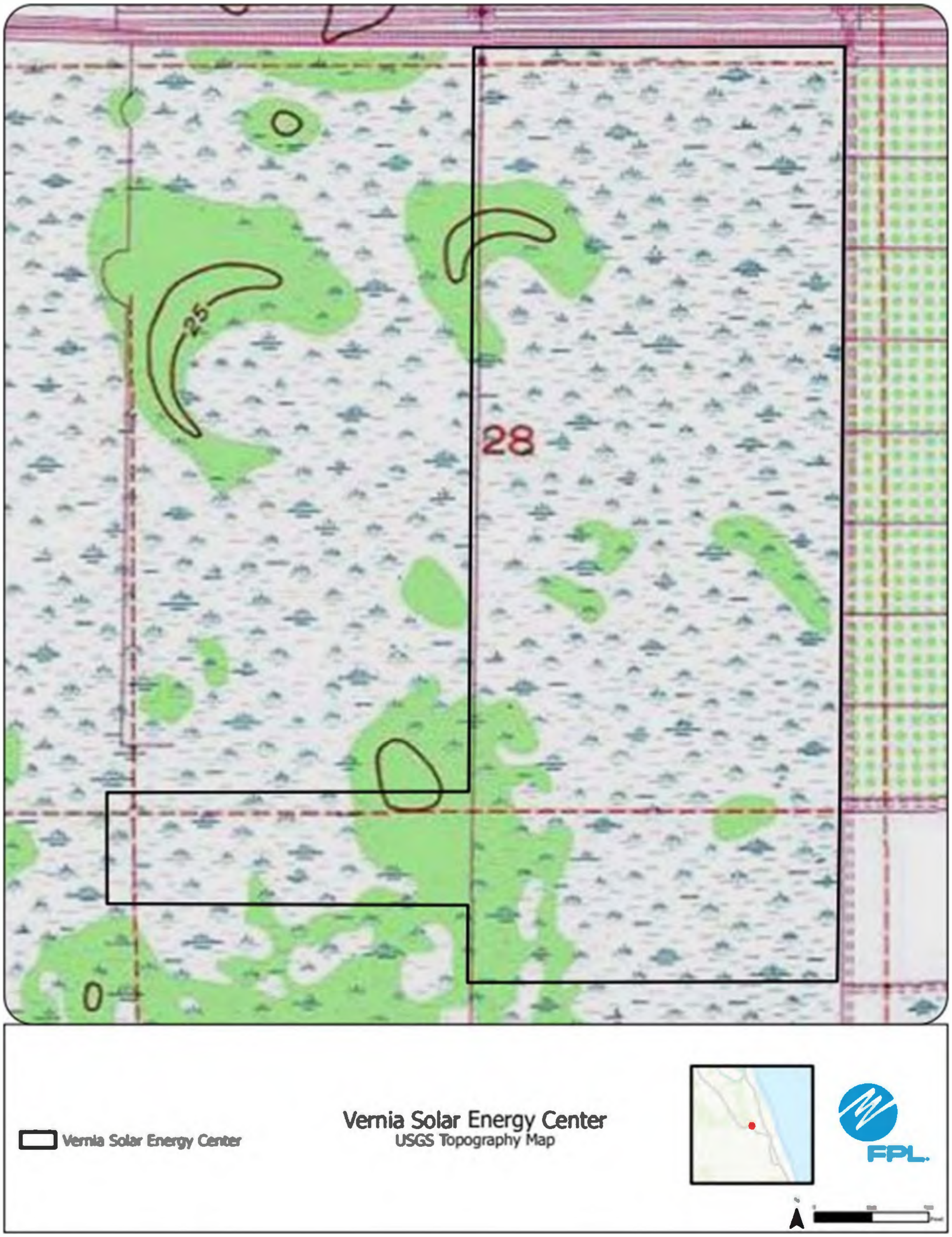

Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Spanish Moss Solar Energy Center
Land Use/Land Cover Map
FPL


Spanish Moss Solar Energy Center
Spanish Moss Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #28: Vernia Solar Energy Center, Indian River County

	Preferred Site	Vernia Solar Energy Center
	County	Indian River
	Facility Acreage	533
	COD	10/31/2027
	For PV facilities: tracking or fixed	Tracking
	Reference Maps	
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.	Existing Land Uses	
	Site	Citrus, improved pasture, forested wetlands, agricultural ditches
	Adjacent Areas	Solar and citrus
f.	General Environment Features On and In the Site Vicinity	
1	Natural Environment	Citrus, improved pasture, forested wetlands, and agricultural ditches
2	Listed Species	Audubon's crested caracara, wading birds
3	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes an approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP: Application not yet submitted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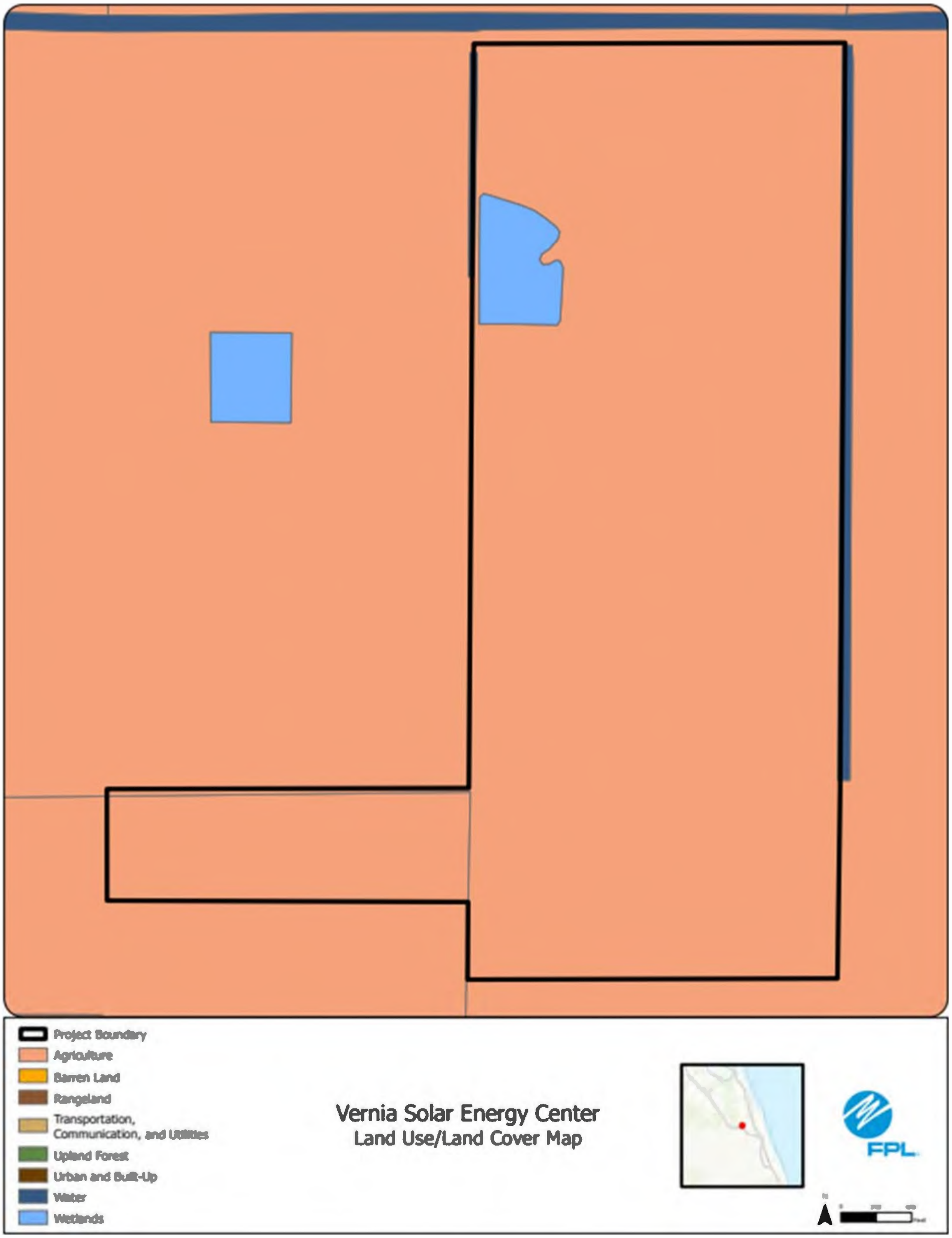
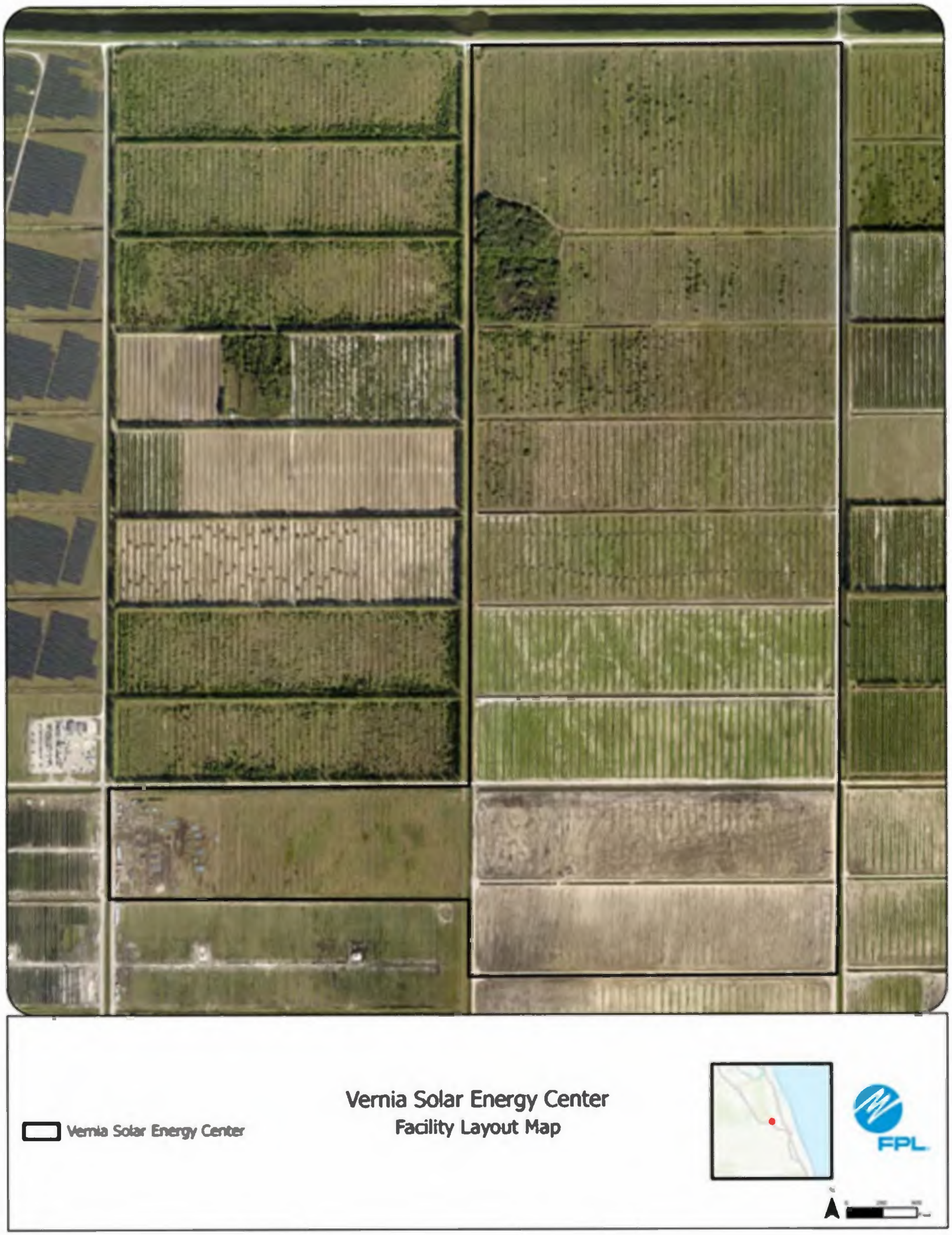
Vernia Solar Energy Center
Vernia Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Vernia Solar Energy Center
Land Use/Land Cover Map
FPL


Vernia Solar Energy Center
Vernia Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #29: LaBelle Solar Energy Center, Hendry County

	Preferred Site	Labelle Solar Energy Center
	County	Hendry
	Facility Acreage	459
	COD	7/31/2028
	For PV facilities: tracking or fixed	Tracking
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Actively managed citrus
	Adjacent Areas	Agricultural lands/low density residential
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	Entire project site is managed citrus with some ponds dug for irrigation.
2.	Listed Species	Audubon's crested caracara
3.	Natural Resources of Regional Significance Status	A few miles north of the project site is the Caloosahatchee River.
4.	Other Significant Features	FPL is not aware of any significant features nearby.
g.	Design Features and Mitigation Options	The design includes a approximately 74.5 MW solar tracking panel PV facility, on-site transmission substation, and site stormwater system. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Solar facilities are permitted in unincorporated agriculturally zoned areas at this time.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing on-site water resources may be used to meet water requirements if a permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked in from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the South region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable: Minimal Panel Cleaning: Minimal and only needed in the absence of sufficient rainfall
m.	Water Supply Sources by Type	Cooling: Not Applicable for Solar Process: Not Applicable for Solar Potable and Panel Cleaning: Onsite well or surface water or delivered to site
n.	Water Conservation Strategies Under Consideration	Solar (PV) does not require a permanent water source. Additional water conservation strategies include selection and planting of low-to-no irrigation grass or groundcover.
o.	Water Discharges and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Solar does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - PV Solar energy generation does not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	PV Solar energy generation does not emit noise therefore there will be no need for noise control systems.
s.	Status of Applications	FDEP ERP: Application not yet submitted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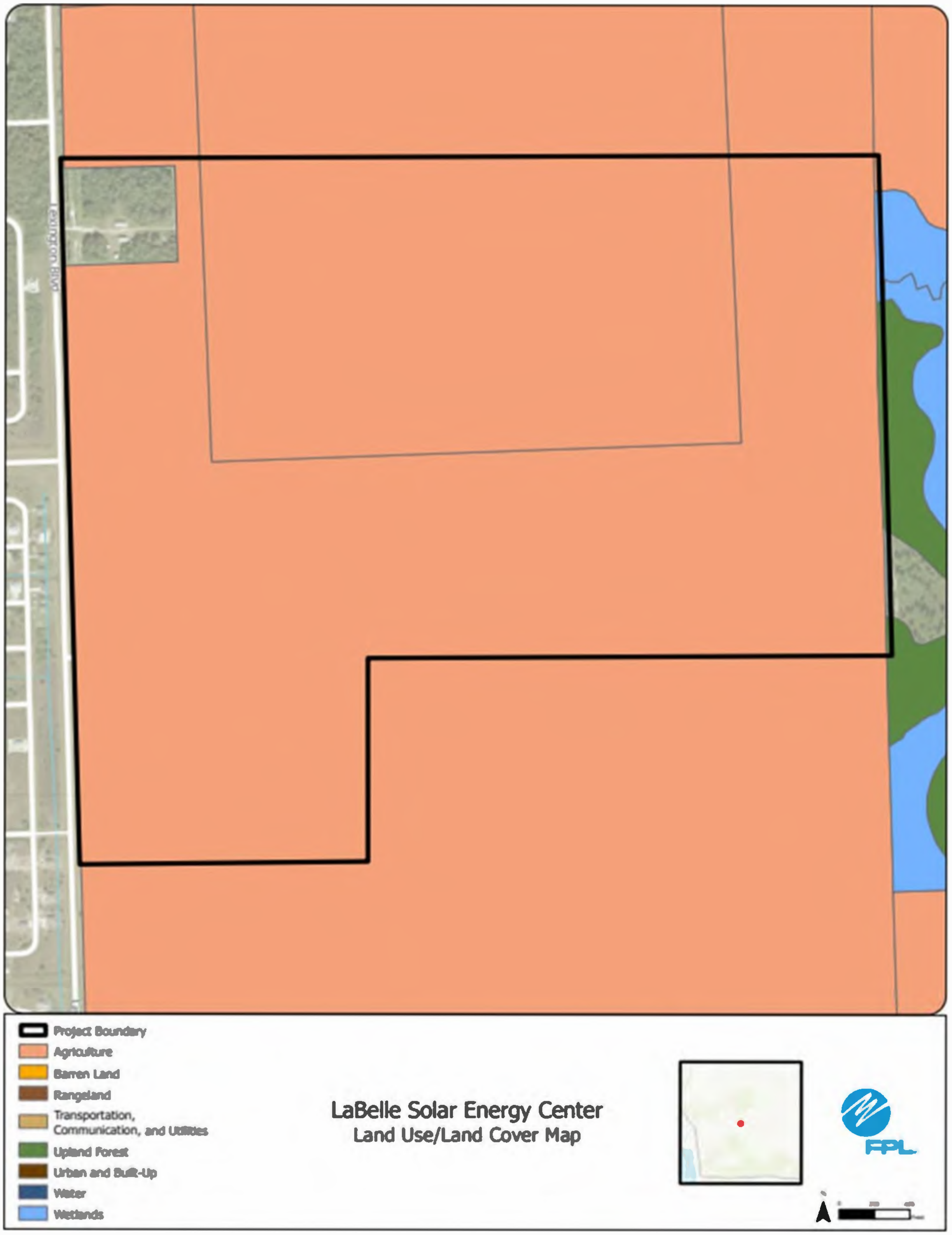
LaBelle Solar Energy Center
LaBelle Solar Energy Center
USGS Topography Map
FPL


Lexington Blvd
Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
LaBelle Solar Energy Center
Land Use/Land Cover Map
FPL

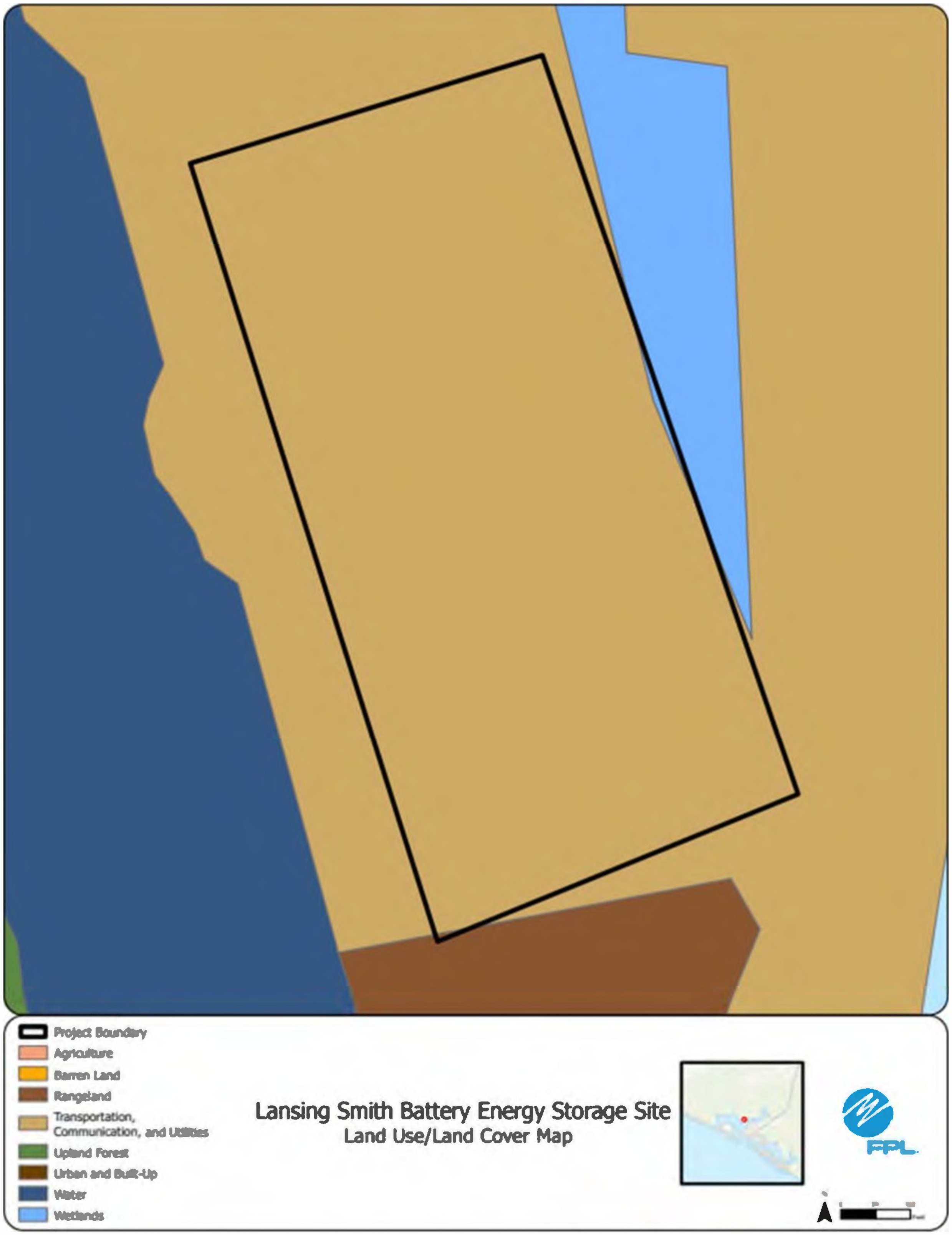

LaBelle Solar Energy Center
LaBelle Solar Energy Center
Facility Layout Map
FPL

Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #30: Lansing Smith Battery Energy Storage Site, Bay County

	Preferred Site	Lansing Smith Battery Energy Storage
	County	Bay
	Facility Acreage	27
	COD	10/31/2026
	For PV facilities: tracking or fixed	N/A
	Reference Maps	
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.	Existing Land Uses	
	Site	FPL Plant Lansing Smith
	Adjacent Areas	North Bay
f.	General Environment Features On and In the Site Vicinity	
1.	Natural Environment	N/A, former coal storage area at FPL Plant Lansing Smith
2.	Listed Species	N/A
3.	Natural Resources of Regional Significance Status	No natural resources of regional significance status at or adjacent to the site.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes 400 MW of 4-hour batteries (1,600MWh total) surrounded by a berm for storm surge protection. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	CSVH Conservation Habitation
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages. Site is located in the North region.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Battery Process: Not Applicable for Battery Potable: Minimal
m.	Water Supply Sources by Type	Cooling: Not Applicable for Battery Process: Not Applicable for Battery Potable: Onsite well or delivered to site
n.	Water Conservation Strategies Under Consideration	Battery projects do not require a permanent water source.
o.	Water Discharges and Pollution Control	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Battery does not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - Battery projects do not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	If applicable, noise control system will be installed if results from any required sound noise studies show the need for one.
s.	Status of Applications	FDEP ERP Issued: 11/15/2024 USACE 404 NWP Issued: 12/16/2024


Lansing Smith Battery Energy Storage Site
Facility Layout Map
Lansing Smith Battery Energy Storage Site
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Lansing Smith Battery Energy Storage Site
Land Use/Land Cover Map
FPL


Lansing Smith Battery Energy Storage Site
Facility Layout Map
Lansing Smith Battery Energy Storage Site
FPL

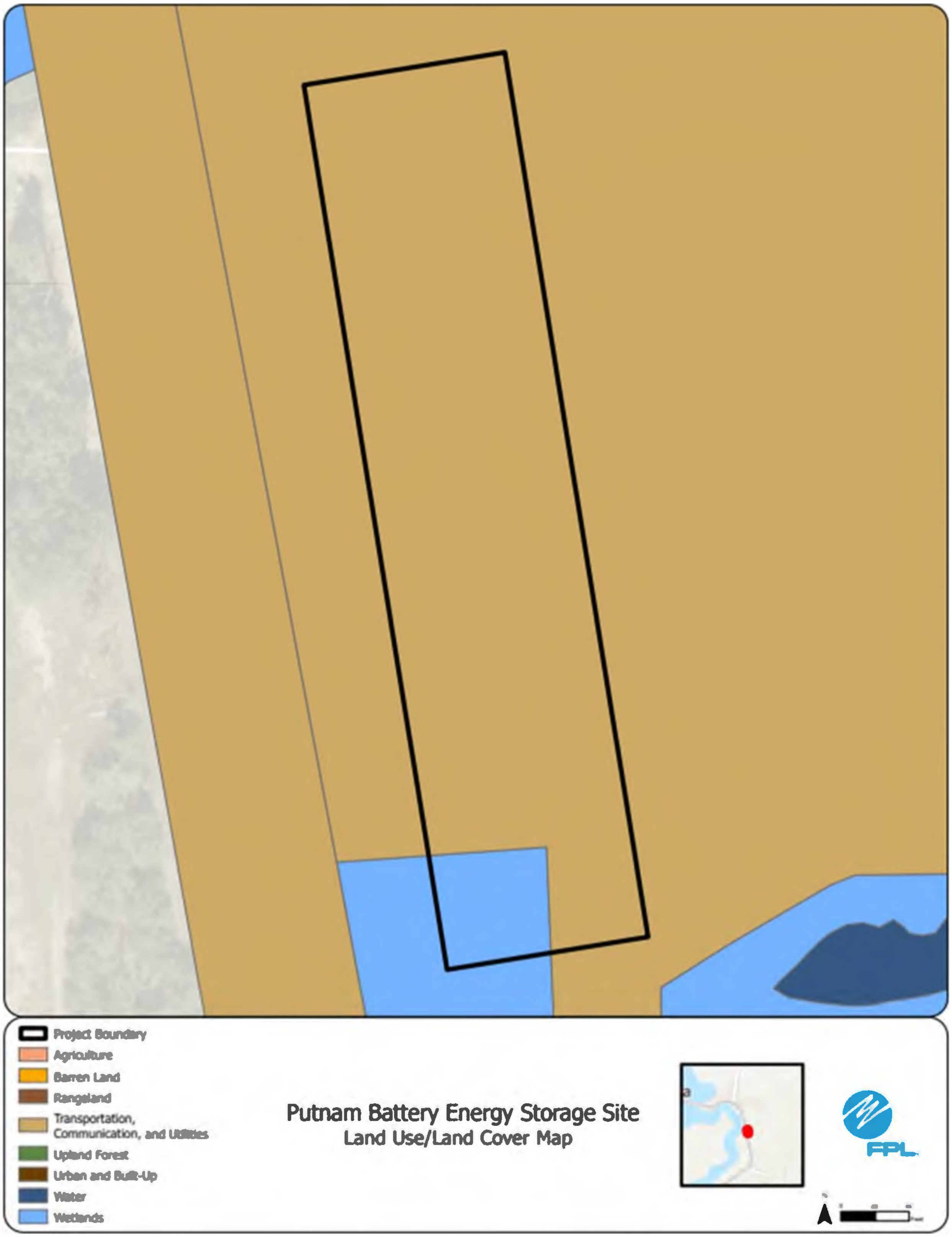
Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #31: Putnam Battery Energy Storage Site, Putnam County

	Preferred Site	Putnam Battery Energy Storage
	County	Putnam
	Facility Acreage	57
	COD	7/31/2027
	For PV facilities: tracking or fixed	N/A
		Reference Maps
a.	USGS Map	See Figures in the following pages
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		Existing Land Uses
	Site	Industrial
	Adjacent Areas	Power generation facilities and highway
f.		General Environment Features On and In the Site Vicinity
1.	Natural Environment	Forested wetlands, disturbed land, shrub and brush, ditches, reservoir
2.	Listed Species	Gopher tortoise
3.	Natural Resources of Regional Significance Status	Site is located along the St.John's River, conservation areas and state parks are in the general vicinity
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	Design Features and Mitigation Options	The design includes a battery energy storage system (BESS), stormwater system, and transmission substation and an on-site transmission interconnection line and ROW. Mitigation for unavoidable impacts, if required, may occur through off-site mitigation.
h.	Local Government Future Land Use Designations	Property is zoned as Industrial Heavy (IH). Previously permitted for industrial power generation facility.
i.	Site Selection Criteria Factors	The site selection criteria included system load, transmission interconnection, economics, and environmental compatibility (e.g., wetlands, wildlife, threatened and endangered species, etc.).
j.	Water Resources	Existing onsite water resources may be used to meet water requirements if permit is pulled or if the facility has an existing CUP/WUP or meets WMD permit-by-rule criteria. Otherwise, water will need to be trucked from off-site.
k.	Geological Features of Site and Adjacent Areas	See Figure in the following pages.
l.	Project Water Quantities for Various Uses	Cooling: Not Applicable for Battery Process: Not Applicable for Battery Potable: Minimal
m.	Water Supply Sources by Type	Cooling: Not Applicable for Battery Process: Not Applicable for Battery Potable: Onsite well or delivered to site
n.	Water Conservation Strategies Under Consideration	Batteries do not require a permanent water source.
o.	Water Discharges and Pollution Control	Best Management Practices (BMPs) will be employed to prevent and control inadvertent release of pollutants.
p.	Fuel Delivery, Storage, Waste Disposal, and Pollution Control	Batteries do not require fuel and no waste products will be generated at the site.
q.	Air Emissions and Control Systems	Fuel - Battery projects do not use any type of combustion fuel; therefore, there will be no air emissions or need for Control Systems. Combustion Control - Not Applicable Combustor Design - Not Applicable
r.	Noise Emissions and Control Systems	If applicable, noise control system will be installed if results from any required sound noise studies show the need for one.
s.	Status of Applications	FDEP ERP: Application not yet submitted

Putnam Battery Energy Storage Site
USGS Topography Map

Putnam Battery Energy Storage Site


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Putnam Battery Energy Storage Site
Land Use/Land Cover Map
FPL

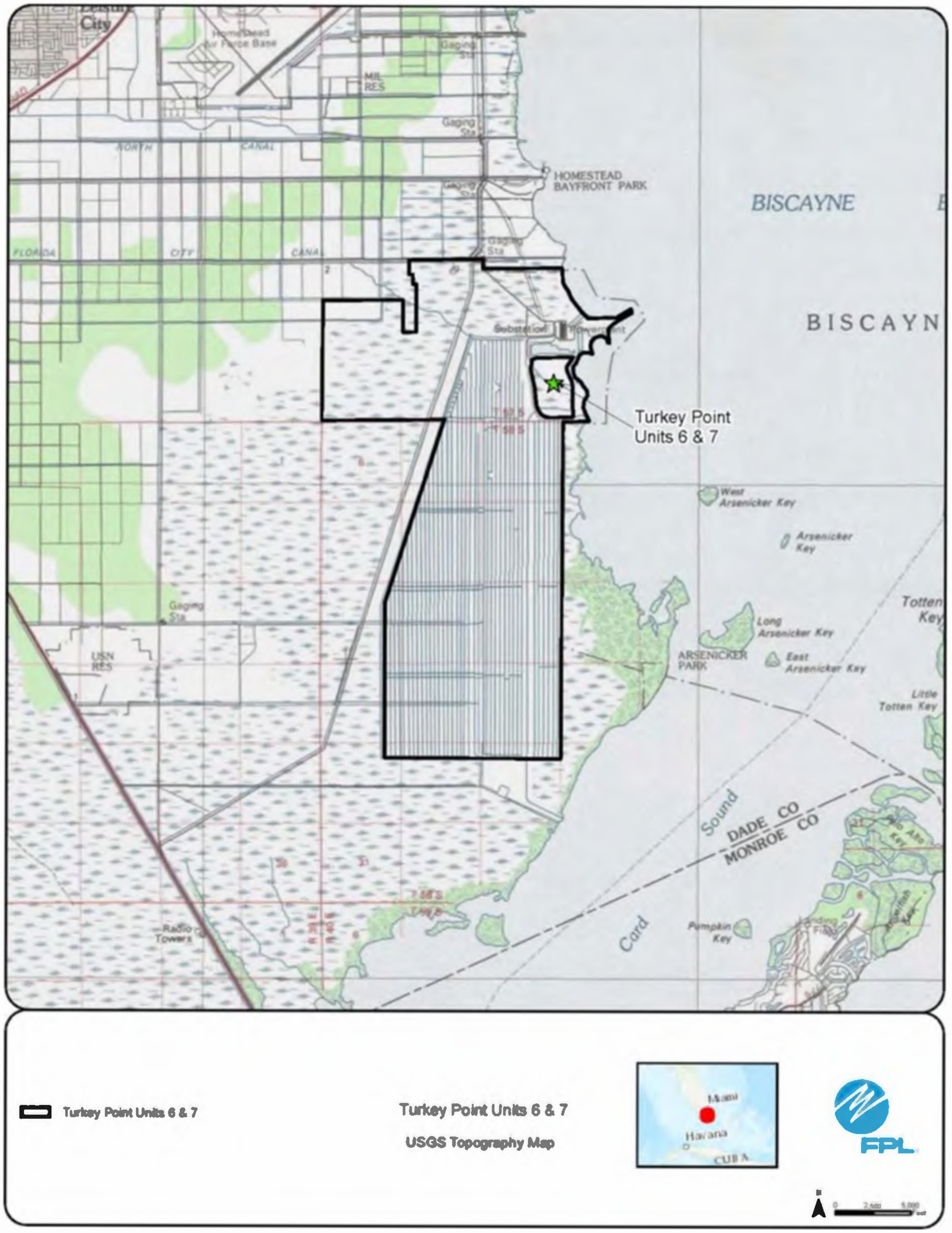
Putnam Battery Energy Storage Site
Facility Layout Map

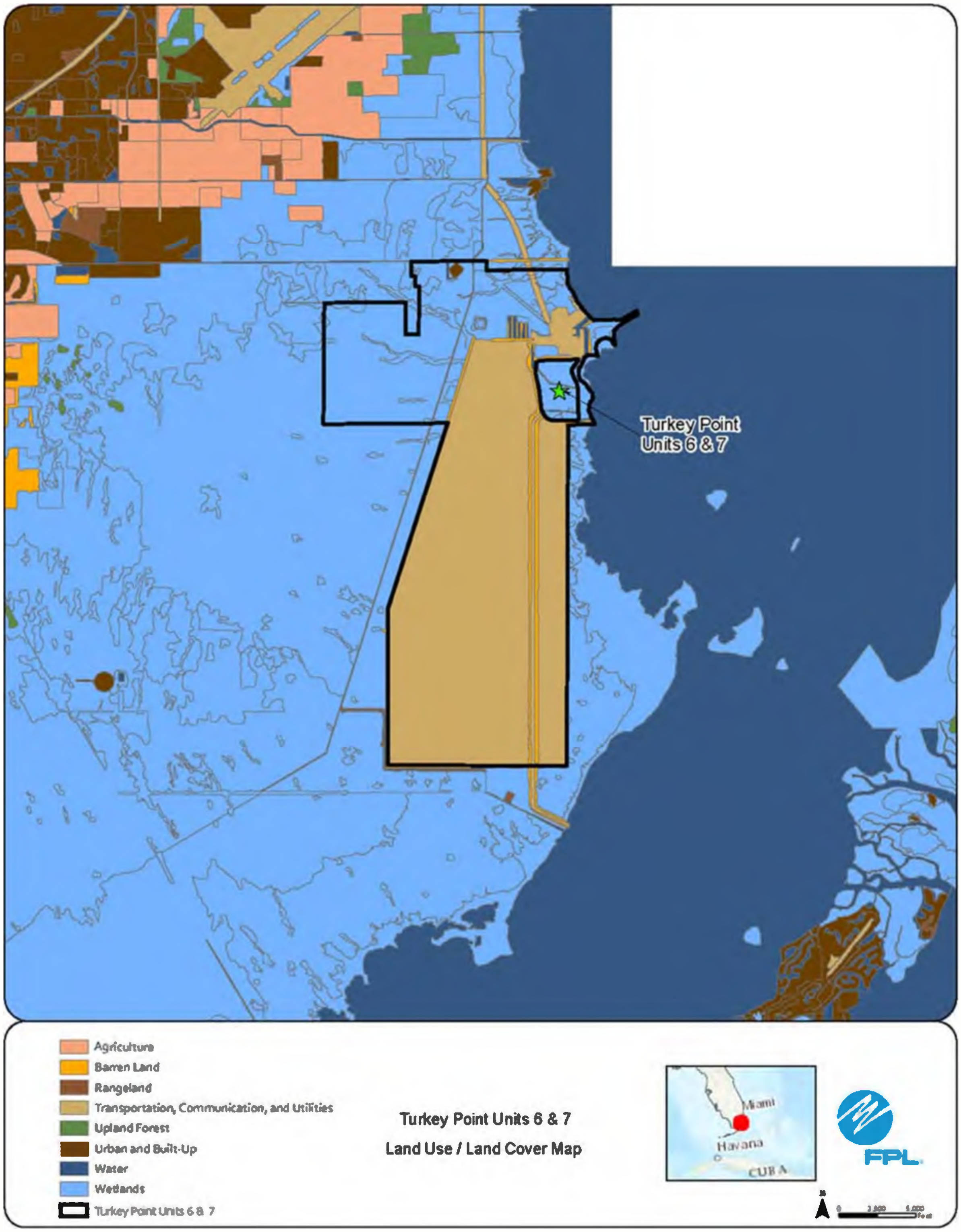
Putnam Battery Energy Storage Site

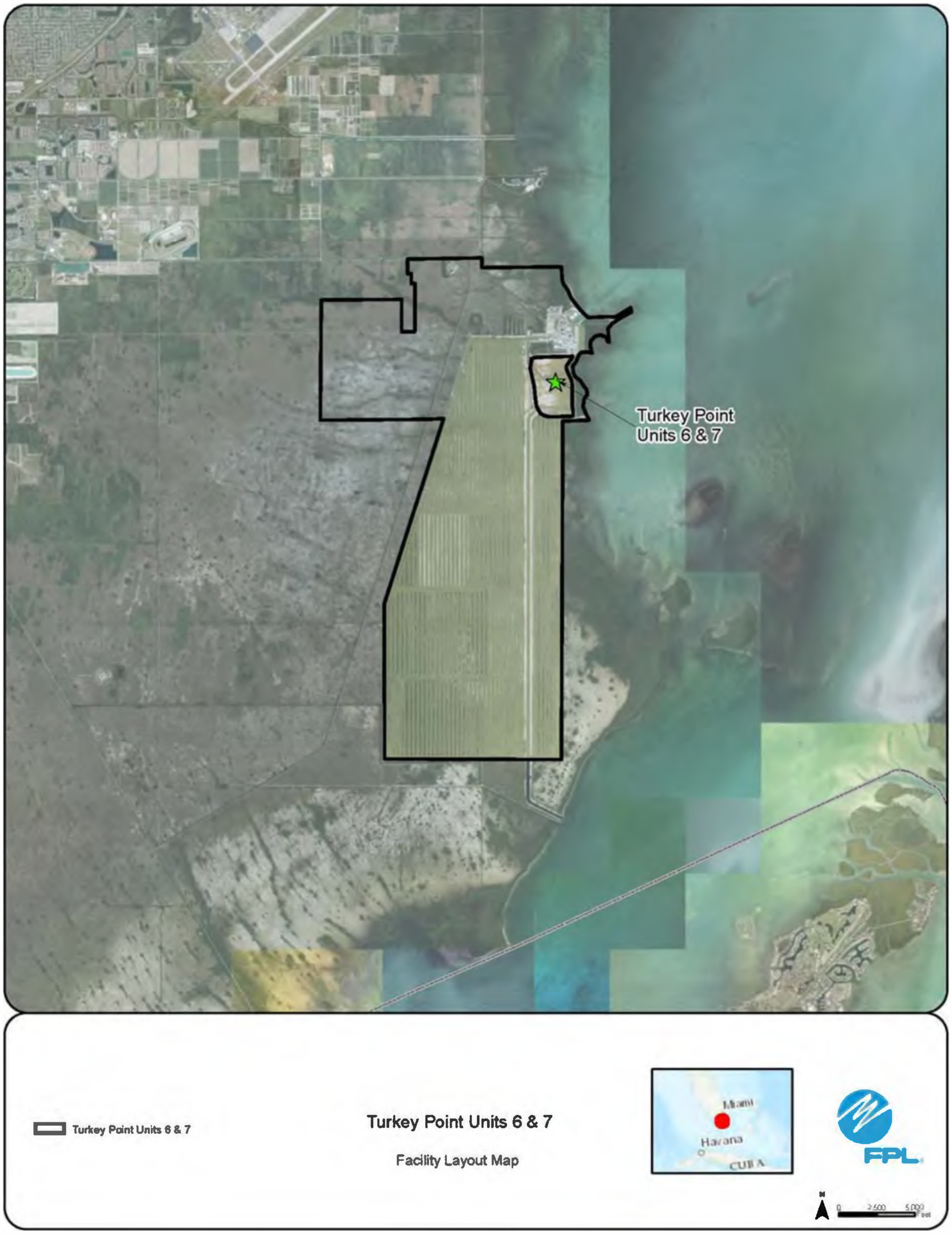
Site Description, Environmental, and Land Use Information: Supplemental Information

Preferred Site #32: Turkey Point Units 6 & 7, Miami-Dade County

	Preferred Site	Turkey Point Units 6&7
	County	Miami-Dade
	Facility Acreage	N/A
	COD	TBD
	For PV facilities: tracking or fixed	N/A
		Reference Maps
a.	USGS Map	See Figures at the end of this chapter
b.	Proposed Facilities Layout	
c.	Map of Site and Adjacent Areas	
d.	Land Use Map of site and Adjacent Areas	
e.		**Existing Land Uses**
	Site	Electrical generating facilities
	Adjacent Areas	Undeveloped, the Everglades Mitigation Bank, South Florida Water Management District Canal L-31E, Biscayne Bay, and state-owned land on Card Sound
f.		**General Environment Features On and In the Site Vicinity**
1.	Natural Environment	The site includes hypersaline mud flats, man-made cooling canals and remnant canals, previously filled areas/roadways, mangrove heads associated with historical tidal channels, dwarf mangroves, open water/discharge canal associated with the cooling canals on the western portion of the site, spoil berms associated with remnant canals, and upland spoil areas.
2.	Listed Species	Listed species known to occur include the peregrine falcon, wood stork, American crocodile, roseate spoonbill, little blue heron, snowy egret, American oystercatcher, least tern, white ibis, Florida manatee, eastern indigo snake, snail kite, and white-crowned pigeon. Some listed flora species likely to occur include pine pink, Florida brickell-bush, Florida lantana, mullein nightshade, and Lamarck's trema. The construction and operation of Turkey Point Units 6 & 7 are not expected to adversely affect listed species.
3.	Natural Resources of Regional Significance Status	Significant features in the vicinity of the site include Biscayne Bay, Biscayne National Park, Biscayne Bay Aquatic Preserve, Miami-Dade County Homestead Bayfront Park, and Everglades National Park.
4.	Other Significant Features	FPL is not aware of any other significant features of the site.
g.	**Design Features and Mitigation Options**	The technology proposed is the Westinghouse AP1000 pressurized water reactor. This design is certified by the Nuclear Regulatory Commission under 10 CFR 52. The Westinghouse AP1000 consists of the reactor, steam generators, pressurizer, and steam turbine/electric generator. The projected generating capacity from each unit is 1,100 MW. Condenser cooling will use six circulating water cooling towers. The structures to be constructed include the containment building, shield building, auxiliary building, turbine building, annex building, diesel generator building, and radwaste building. The plant area will also contain the Clear Sky substation (switchyard) that will connect to FPL's transmission system.
h.	**Local Government Future Land Use Designations**	Current future land use designations include Industrial, Utilities, Communications, and Unlimited Manufacturing with a dual designation of Mangrove Protection Area. There are also areas of the site designated Interim District.
i.	**Site Selection Criteria Factors**	Site selection included the following criteria: existing transmission and transportation infrastructure to support new generation, the size and seclusion of the site while being relatively close to the load center, economics, and the long-standing record of safe and secure operation of nuclear generation at the site since the early 1970s.
j.	**Water Resources**	Water requirements will be met by reclaimed water from Miami-Dade County and a back-up supply of saline groundwater from below the marine environment of Biscayne Bay.
k.	**Geological Features of Site and Adjacent Areas**	See Figure at the end of this Chapter. The site is located in the South Florida region.
l.	**Project Water Quantities for Various Uses**	Cooling: 55.3 million gallons per day (mgd) Process: 1.3 mgd Potable: .05 mgd Panel Cleaning: Not Applicable
m.	**Water Supply Sources by Type**	Cooling: Miami-Dade reclaimed water and saline groundwater from Biscayne Bay via radial collector wells Process: Miami-Dade Water and Sewer Department Potable: Miami-Dade Water and Sewer Department
n.	**Water Conservation Strategies Under Consideration**	Turkey Point Units 6 & 7 will use reclaimed water 24 hours per day, 365 days per year when operating and when the reclaimed water is available in sufficient quantity and quality.
o.	**Water Discharges and Pollution Control**	Blowdown water or discharge from the cooling towers, along with other waste streams, will be injected into the boulder zone of the Floridan Aquifer. Non-point source discharges are not an issue since there will be none at this facility. Stormwater runoff will be released to the closed-loop cooling canal system.
p.	**Fuel Delivery, Storage, Waste Disposal, and Pollution Control**	The Turkey Point Units 6 & 7 reactors will contain enriched uranium fuel assemblies. Fuel assemblies will be transported to Turkey Point for use in Units 6 & 7 by truck from a fuel fabrication facility in accordance with U.S. Department of Transportation and NRC regulations. Spent fuel being discharged will remain in the permitted spent fuel pool while short half-life isotopes decay. After a sufficient decay period, the fuel would be transferred to an on-site independent spent fuel storage installation facility or a permitted off-site disposal facility. Packaging of the fuel for off-site shipment will comply with the applicable DOT and NRC regulations for transportation of radioactive material. The U.S. Department of Energy is responsible for spent fuel transportation from reactor sites to a repository under the Nuclear Waste Policy Act of 1982, as amended. FPL has executed a standard spent nuclear fuel disposal contract with DOE for fuel used in Units 6 & 7.
q.	**Air Emissions and Control Systems**	Fuel - The units will minimize FPL system air pollutant emissions by using nuclear fuel to generate electric power. Combustion Control / Combustor Design - Not Applicable Note: The diesel engines necessary to support Turkey Point Units 6 & 7 and fire pump engines will be purchased from manufacturers whose engines meet the EPA's New Source Performance Standards Subpart IIII emission limits.
r.	**Noise Emissions and Control Systems**	Predicted noise levels associated with these projects are not expected to result in adverse noise impacts in the vicinity of the site.
s	**Status of Applications**	Need Determination Issued: April 2008 FL Site Certification Received: May 14, 2014 USACE Section 404 Permit: December 18, 2019 COL received: April 5, 2018 Miami-Dade County Unusual Use approvals: issued in 2007 and 2013 Land Use Consistency Determination: issued in 2013 Prevention of Significant Deterioration: issued in 2009


HOMESTEAD BAYFRONT PARK
BISCAYNE
BISCAYN
Substation
Turkey Point
Units 6 & 7
West Arsenicker Key
Arsenicker Key
Long Arsenicker Key
East Arsenicker Key
ARSENICKER PARK
Totten Key
Little Totten Key
DADE CO
MONROE CO
Card Sound
Pumpkin Key
NORTH CANAL
FLORIDA CITY CANAL
USN RES
MIL RES
Gaging Sta
Radio Towers
Turkey Point Units 6 & 7
Turkey Point Units 6 & 7
USGS Topography Map
Miami
Havana
CUBA
FPL


Turkey Point
Units 6 & 7
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Turkey Point Units 6 & 7
Turkey Point Units 6 & 7
Land Use / Land Cover Map
Miami
Havana
CUBA
FPL


Turkey Point
Units 6 & 7
Turkey Point Units 6 & 7
Turkey Point Units 6 & 7
Facility Layout Map
Miami
Havana
CUBA
FPL

Appendix C Potential Sites

Below are the descriptions regarding each of the 18 Potential Sites listed in Table IV.G.2 in Chapter IV. Following the descriptions are maps showing the topographical features, land use, and facility layout of each site.

FPL Area Potential Site #1: Waveland Solar Energy Center

This potential site in St. Lucie County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is currently improved pasture with agricultural ditches. Surrounding area is improved pasture, fallow agriculture and various active agriculture.

c. Environmental Features

Site consists mainly of improved pasture with agricultural ditches. Listed species include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

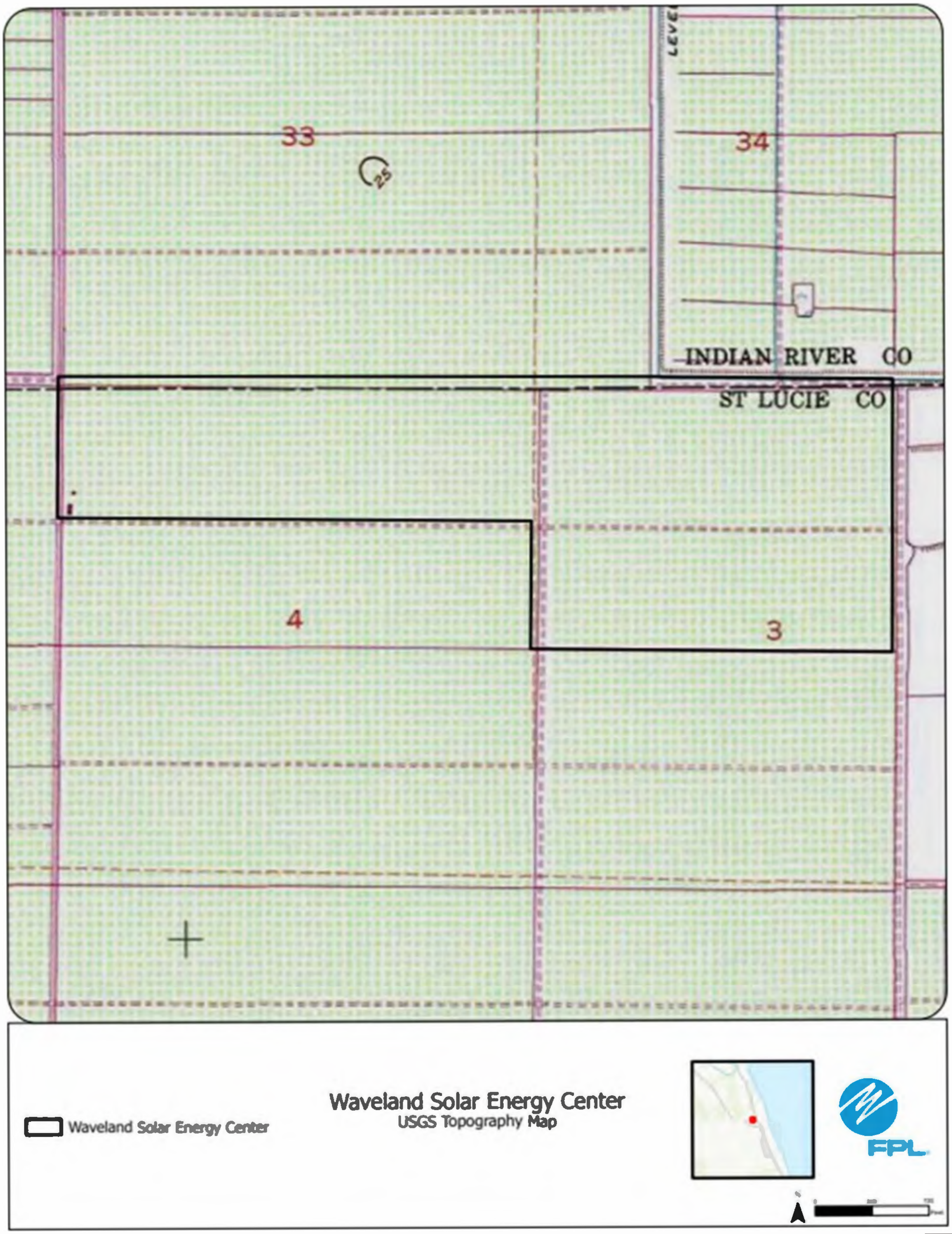
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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INDIAN RIVER CO
ST LUCIE CO
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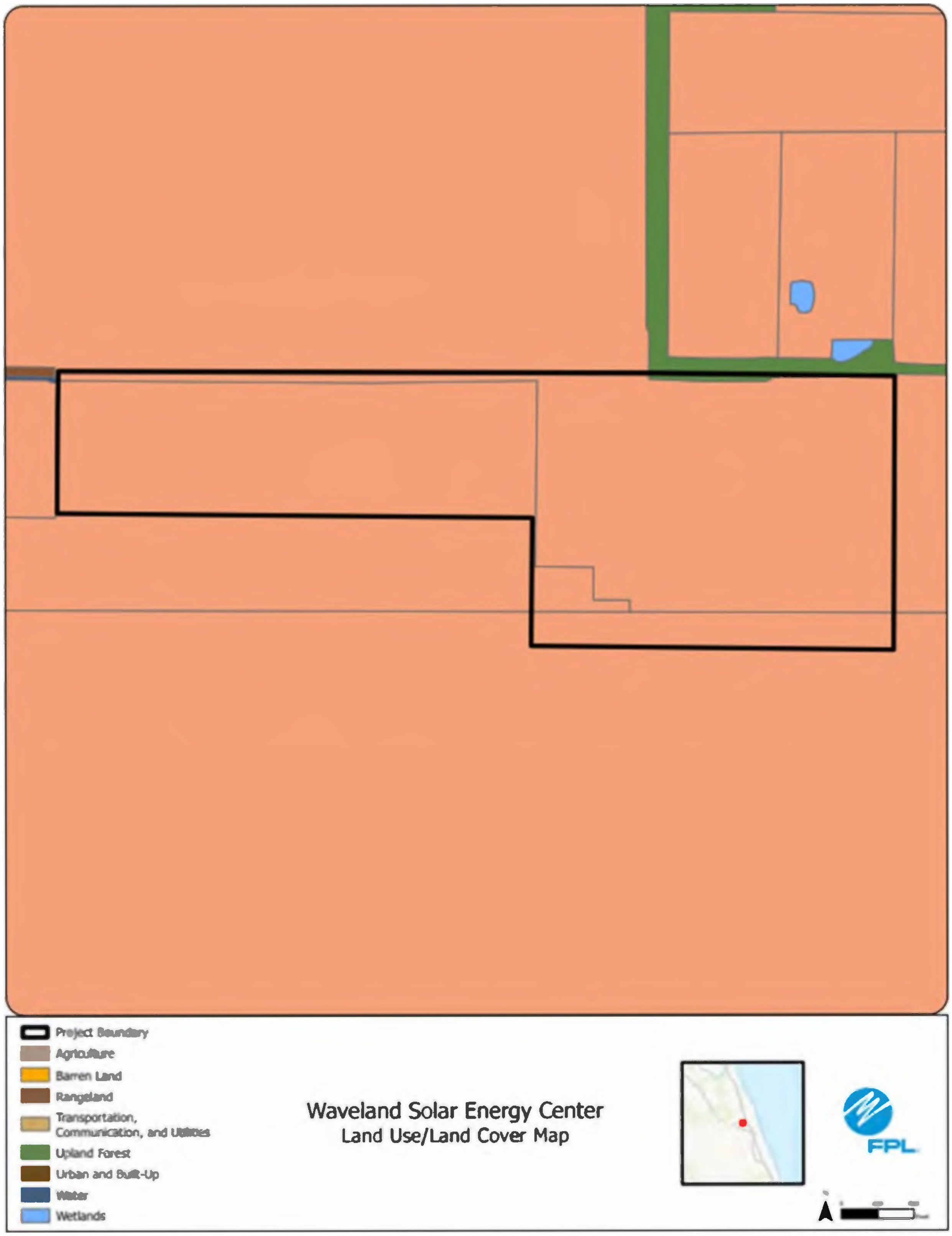
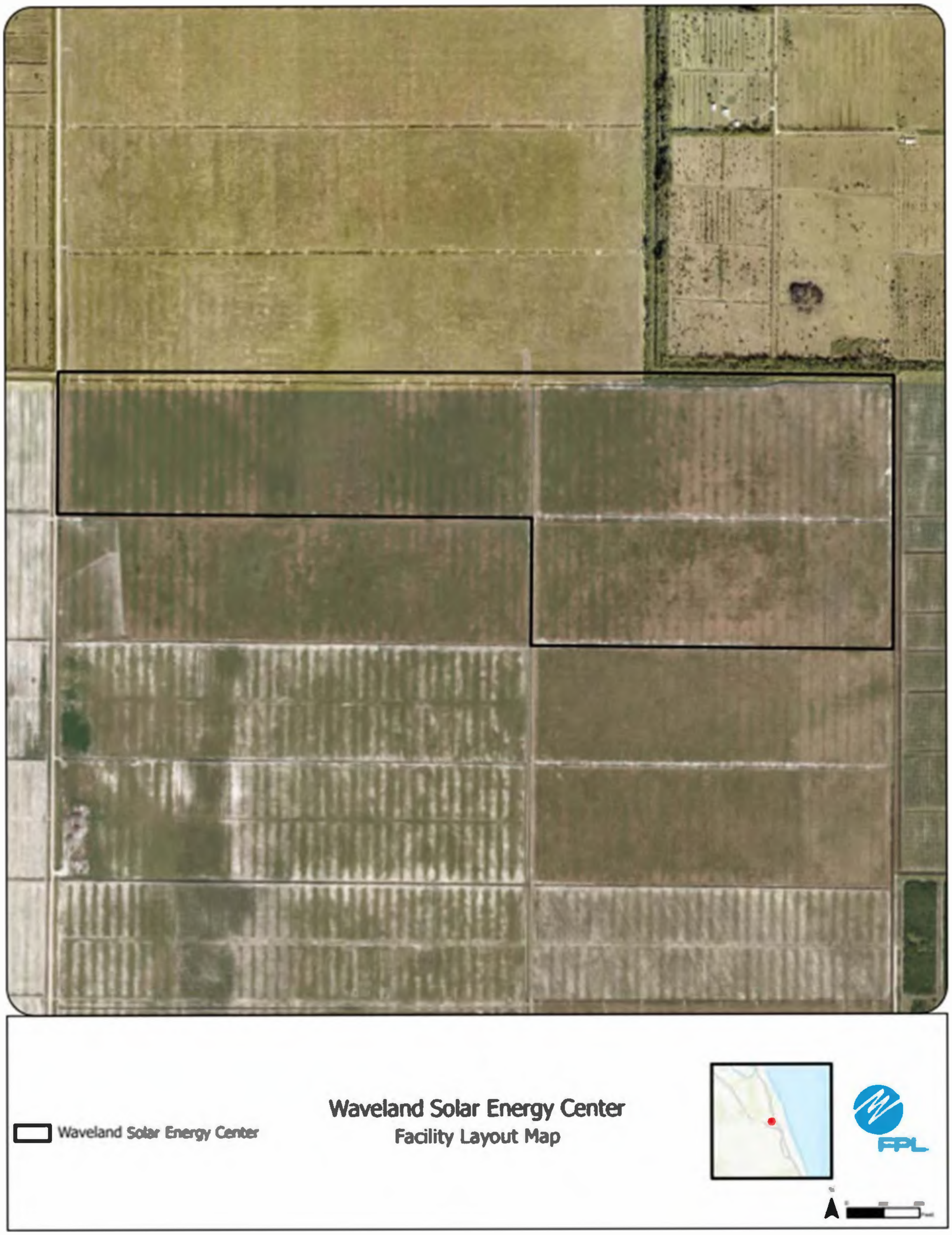
Waveland Solar Energy Center
Waveland Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Waveland Solar Energy Center
Land Use/Land Cover Map
FPL


Waveland Solar Energy Center
Waveland Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #2: Inlet Solar Energy Center

This potential site in Indian River County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site consists of improved pasture with agricultural ditches. Surrounding area is categorized by fallow agriculture, improved pasture and an adjacent solar energy center. A cell tower (not owned by FPL) is located in the central/west portion of the project area.

c. Environmental Features

The entire site is improved pasture with agricultural ditches. Listed species include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

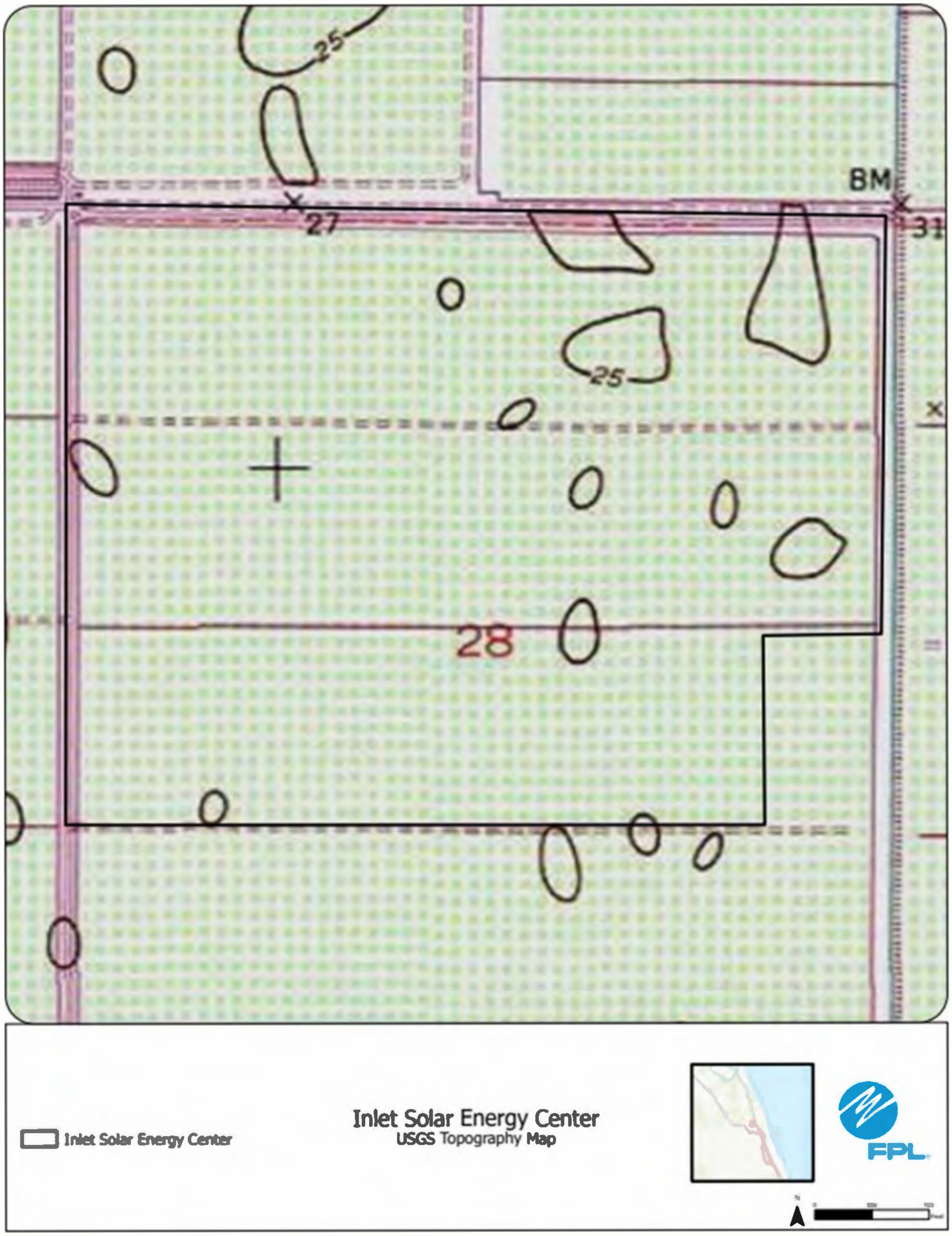
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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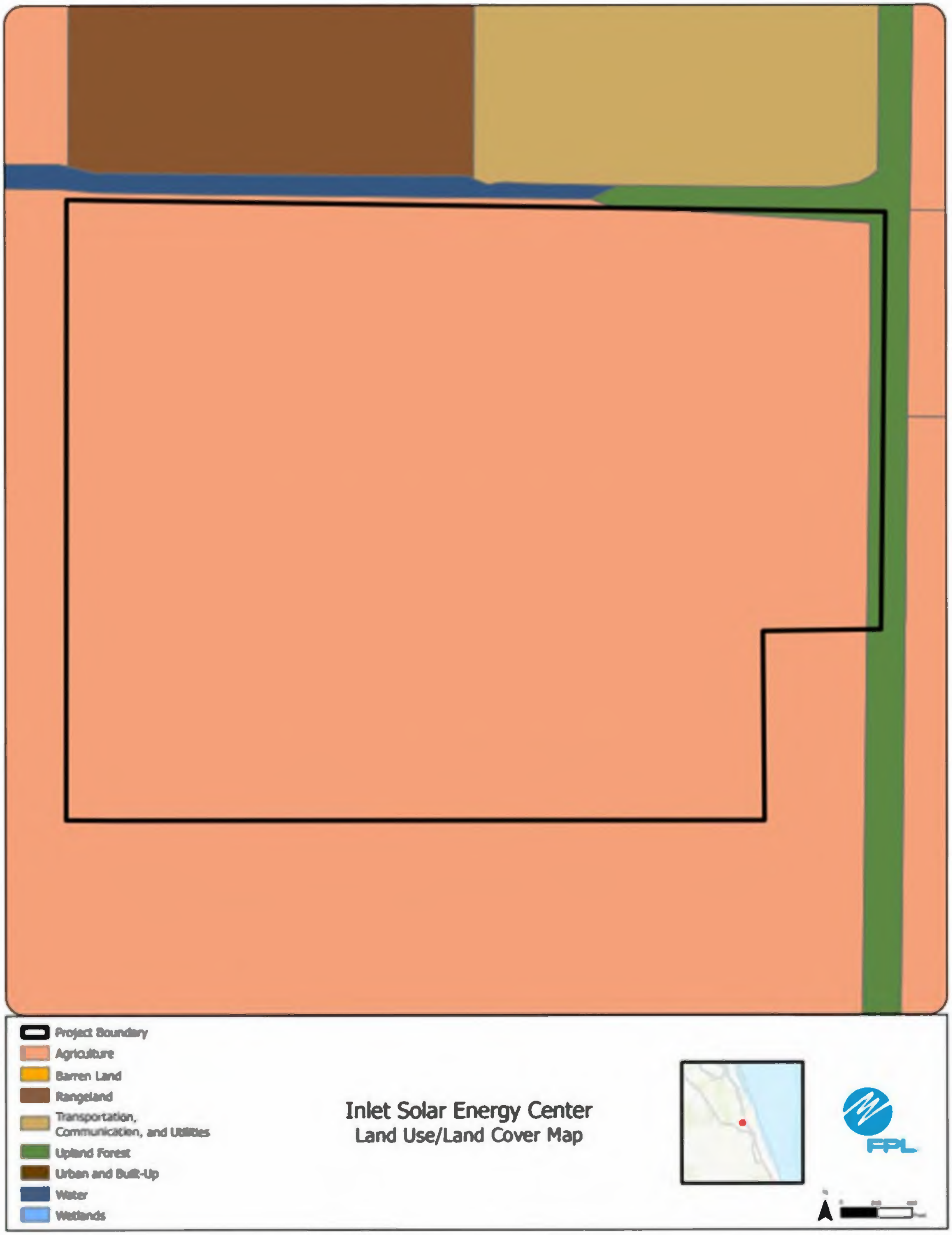
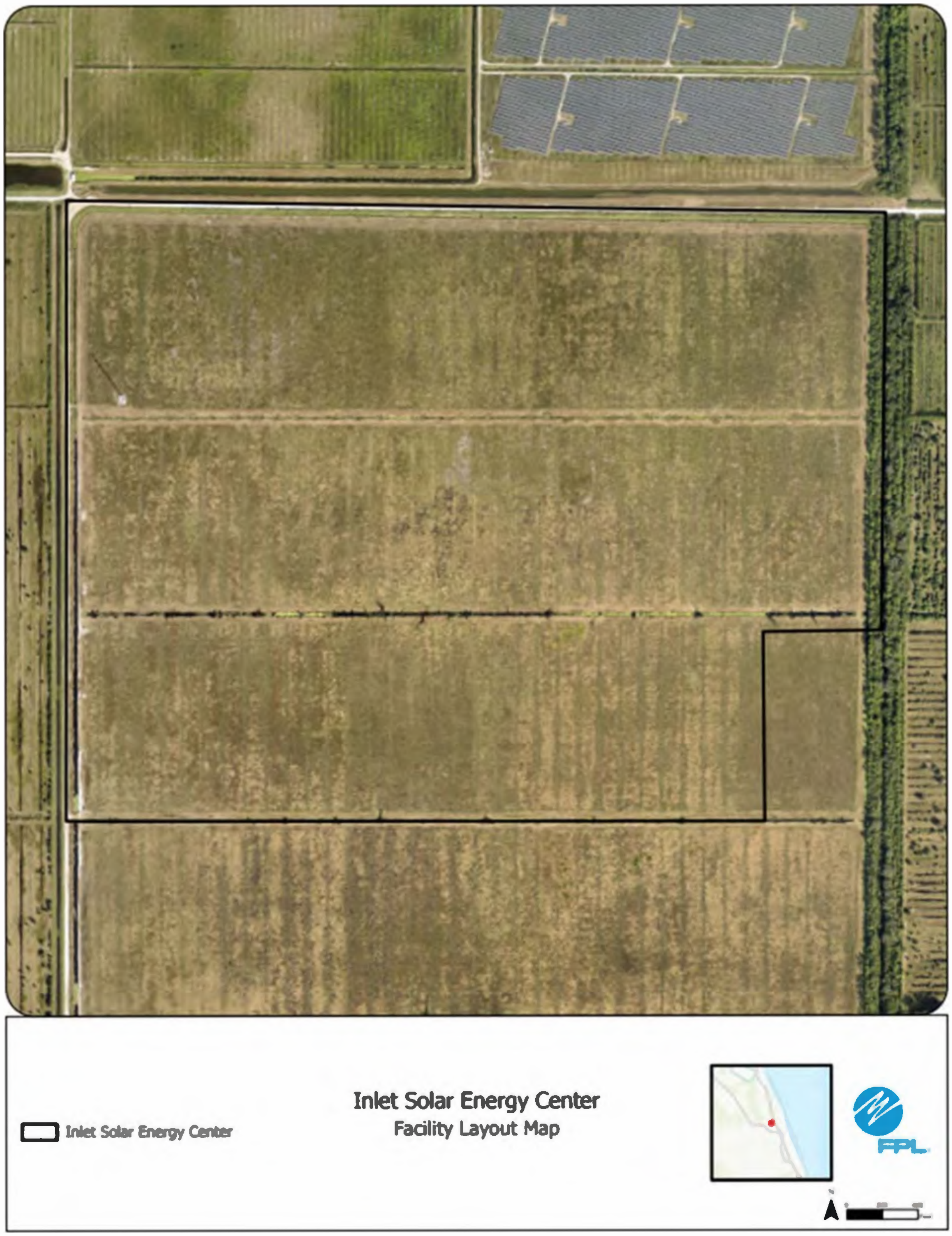
Inlet Solar Energy Center
Inlet Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Inlet Solar Energy Center
Land Use/Land Cover Map
FPL


Inlet Solar Energy Center
Inlet Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #3: Wabasso Solar Energy Center

This potential site in Indian River County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is improved pasture and citrus. Surrounding area includes citrus groves and an adjacent solar energy center.

c. Environmental Features

Site is primarily citrus and improved pasture with agricultural ditches throughout the property. Listed species expected in the vicinity of the project are Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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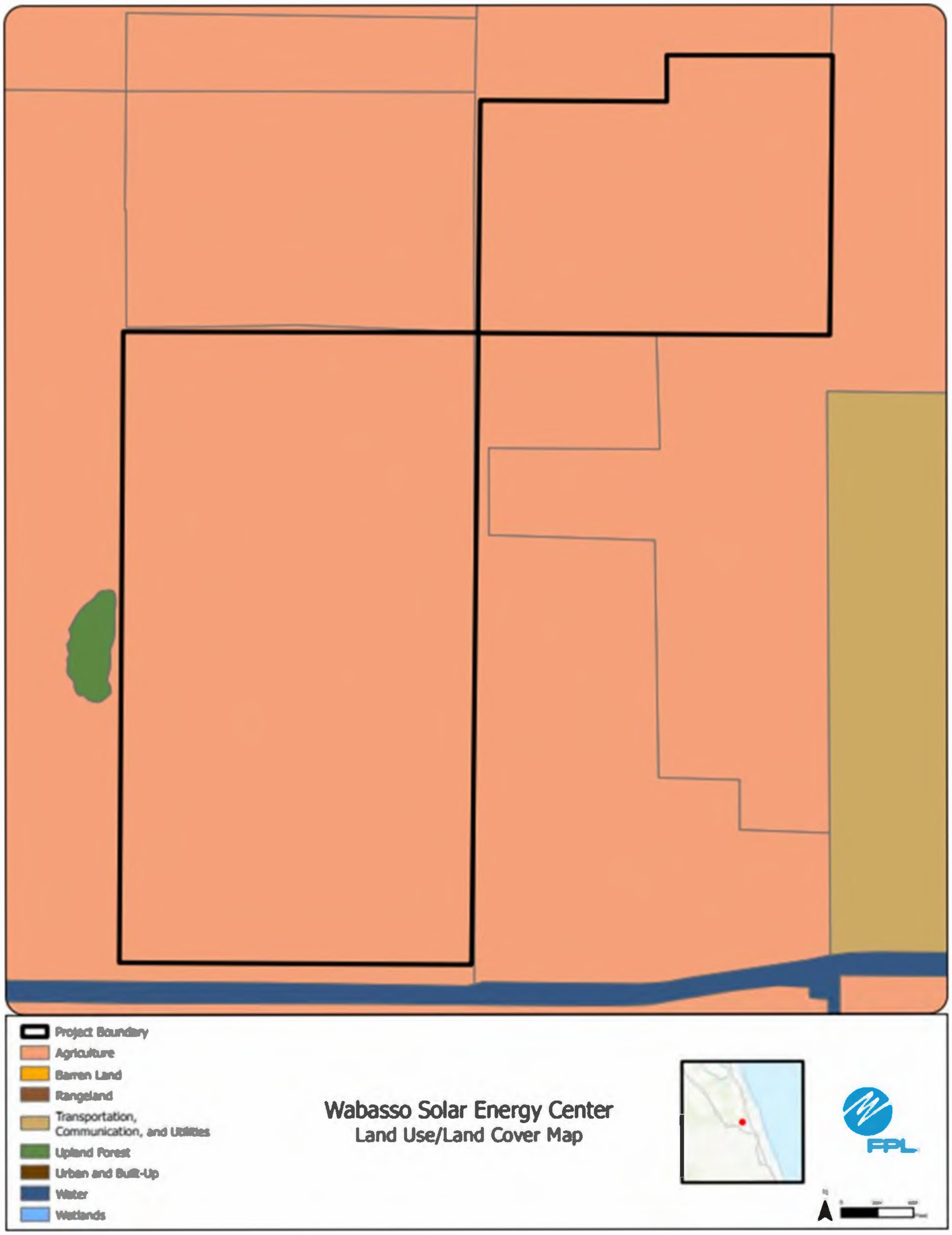
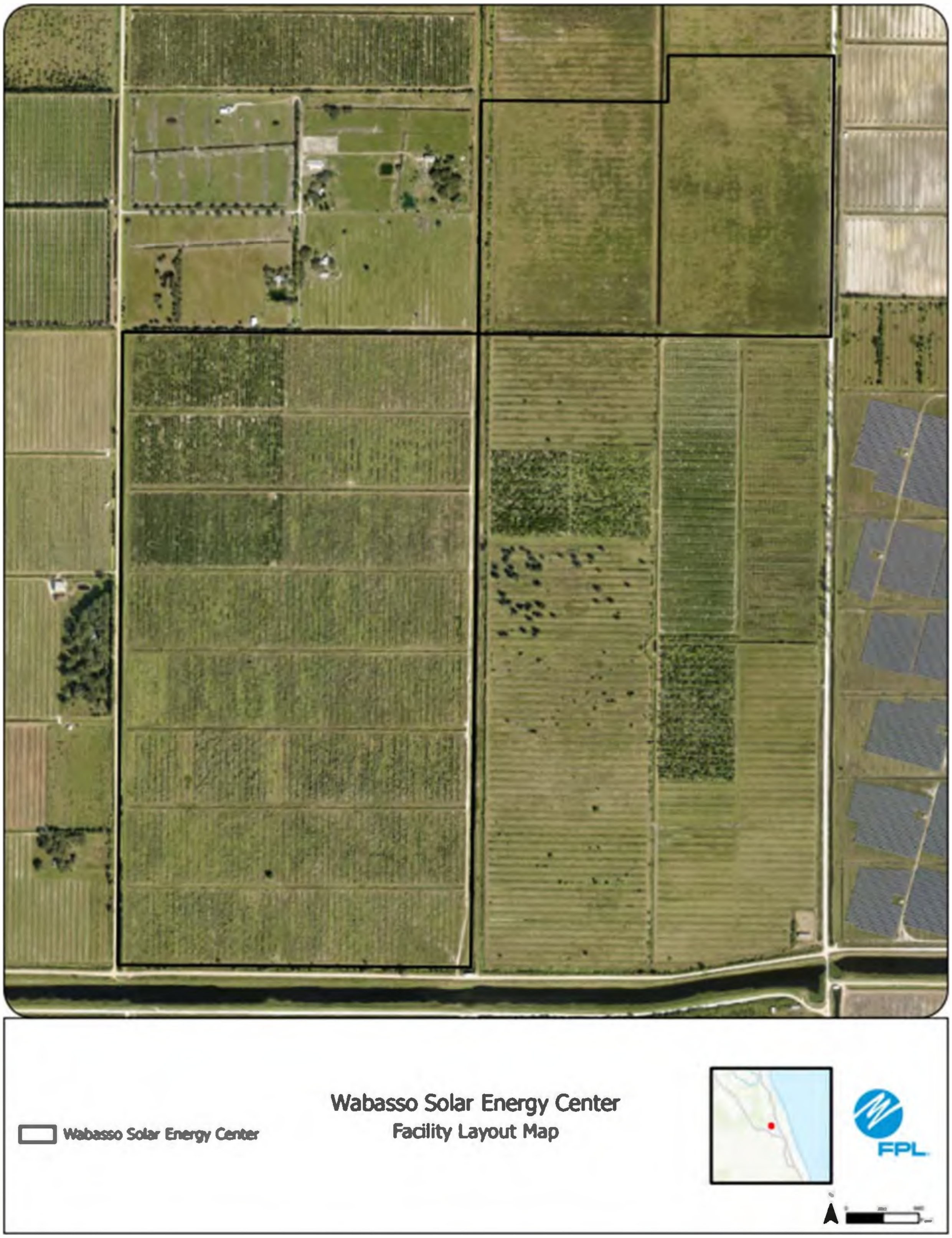
Wabasso Solar Energy Center
Wabasso Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Wabasso Solar Energy Center
Land Use/Land Cover Map
FPL


Wabasso Solar Energy Center
Wabasso Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #4: Shores Solar Energy Center

This potential site in Indian River County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is improved pasture and citrus. Surrounding area includes agricultural ditches, citrus groves and an adjacent solar energy center.

c. Environmental Features

Site is primarily citrus and improved pasture with agricultural ditches throughout the property. Listed species expected in the vicinity of the project are Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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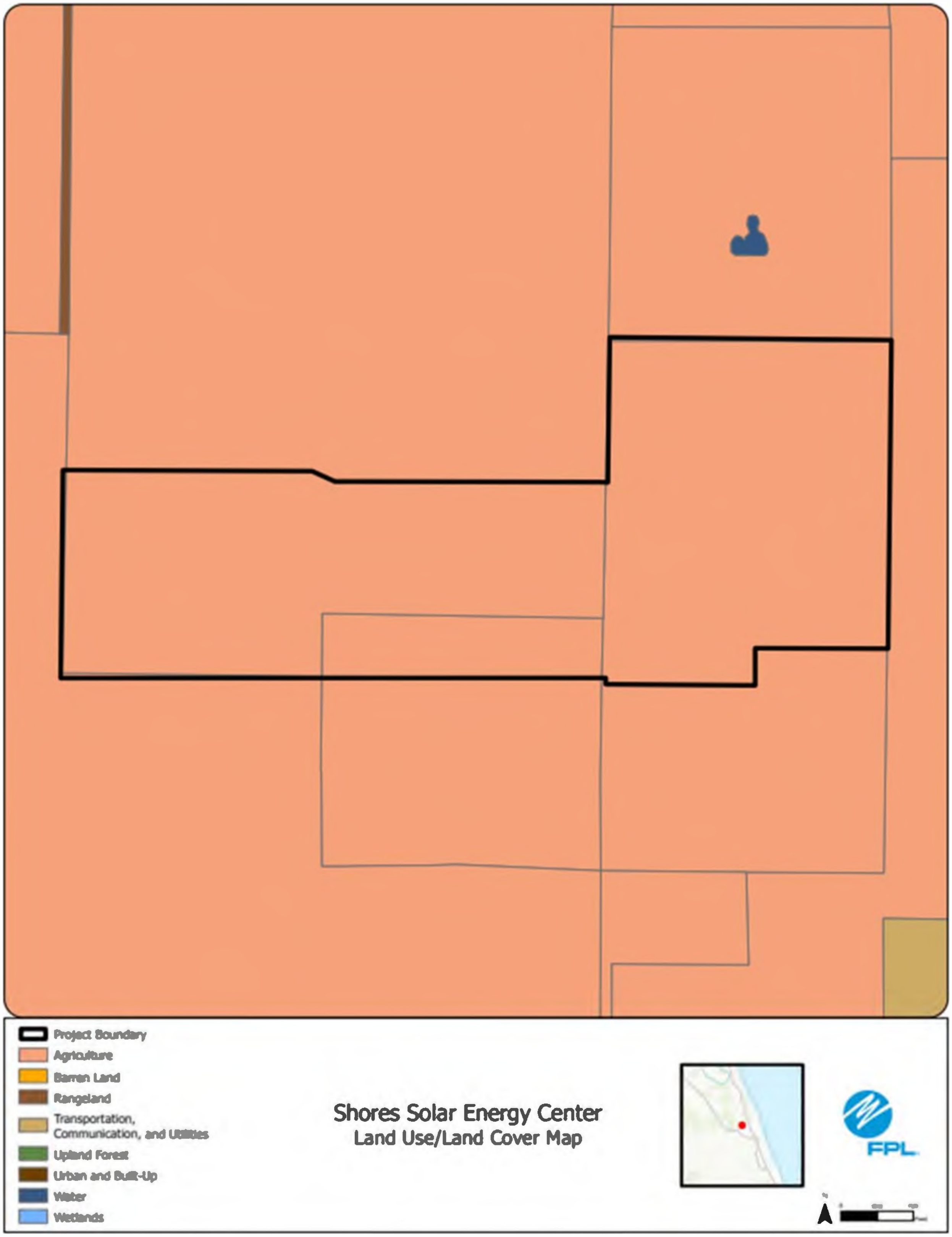
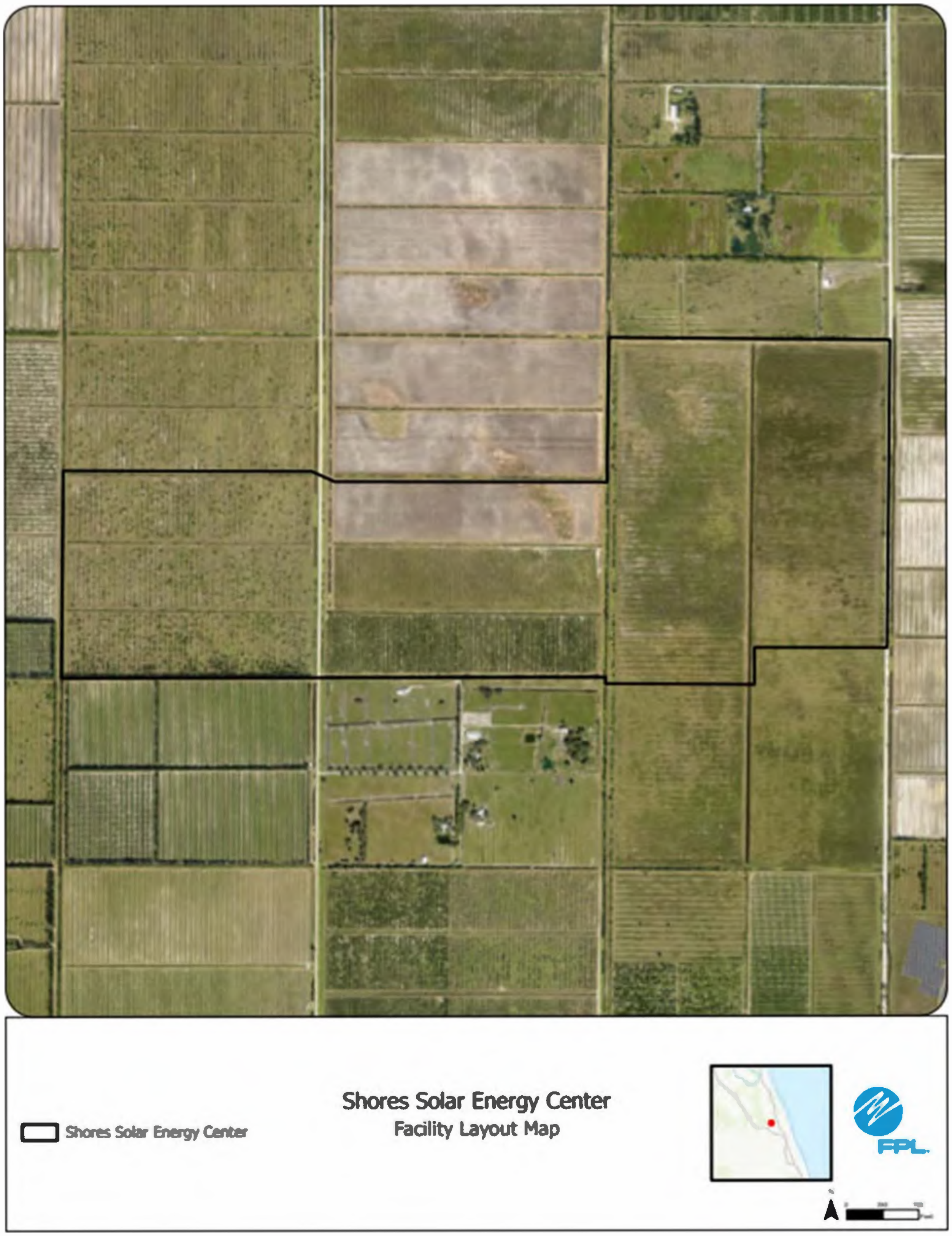
Shores Solar Energy Center
Shores Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Shores Solar Energy Center
Land Use/Land Cover Map
FPL


Shores Solar Energy Center
Shores Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #5: Beachland Solar Energy Center

This potential site in Indian River County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is improved pasture and citrus. Surrounding area includes agricultural ditches, citrus groves and an adjacent solar energy center.

c. Environmental Features

Site is primarily citrus and improved pasture with agricultural ditches throughout the property. Listed species expected in the vicinity of the project are Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

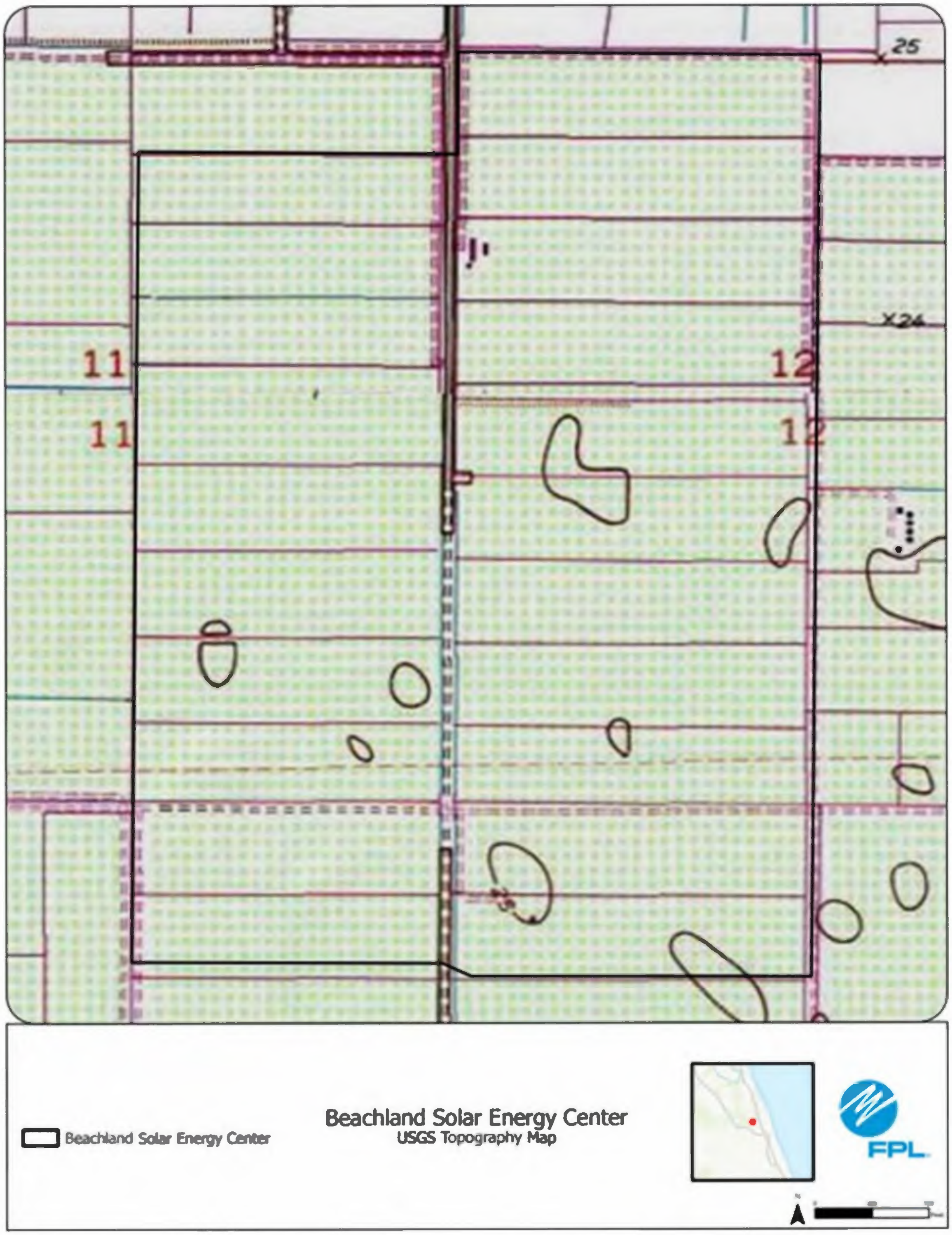
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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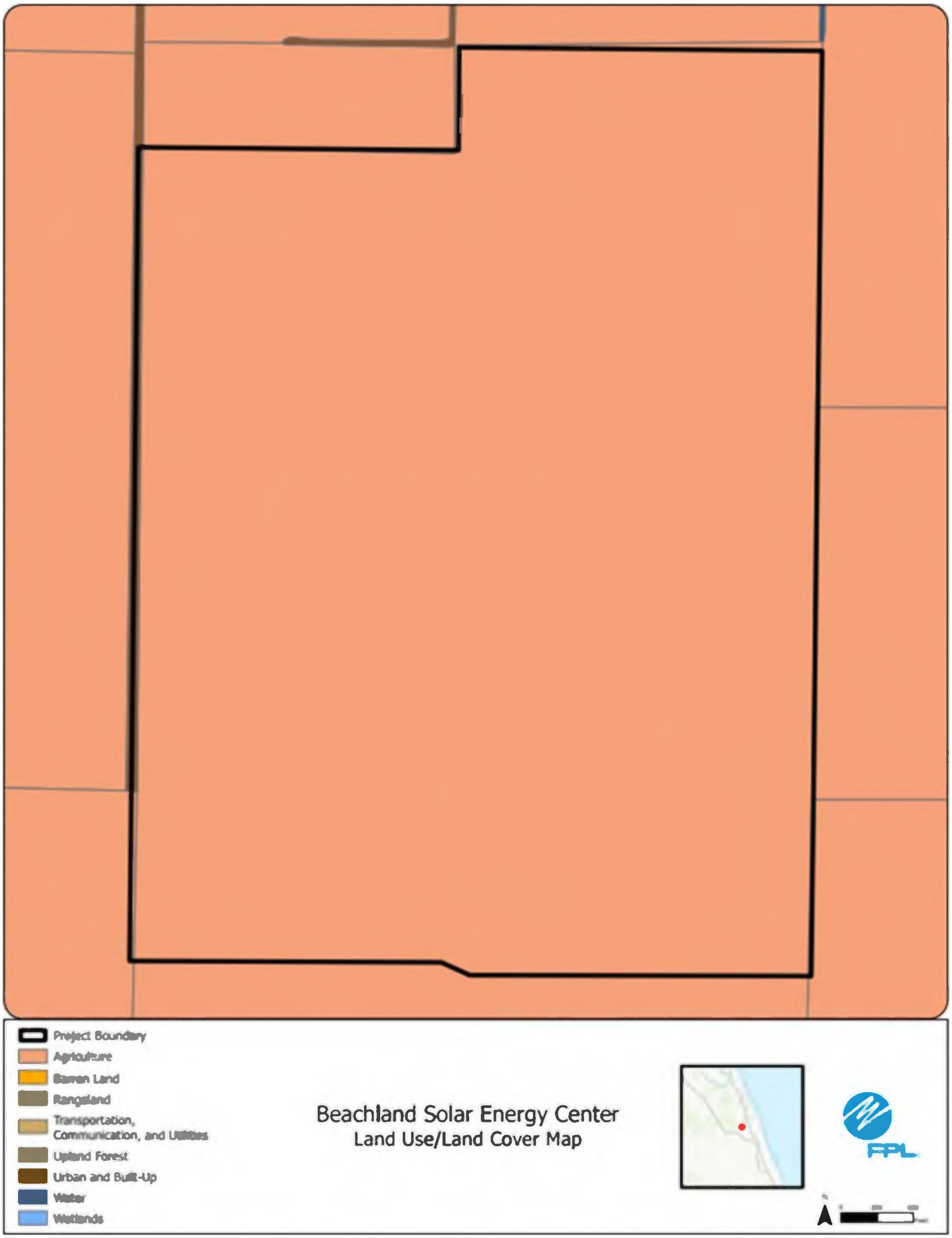
Beachland Solar Energy Center
Beachland Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Beachland Solar Energy Center
Land Use/Land Cover Map
FPL


Beachland Solar Energy Center
Beachland Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #6: Treefrog Solar Energy Center

This potential site in Collier County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

The site and the surrounding area consist of various agricultural activities.

c. Environmental Features

Site is generally comprised of various agricultural areas and wetlands. Listed species in the vicinity of the project include the Audubon's crested caracara, Florida panther and gopher tortoise. No adverse impacts to listed species are anticipated. Corkscrew Swamp is located approximately 5,000 feet to the west.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

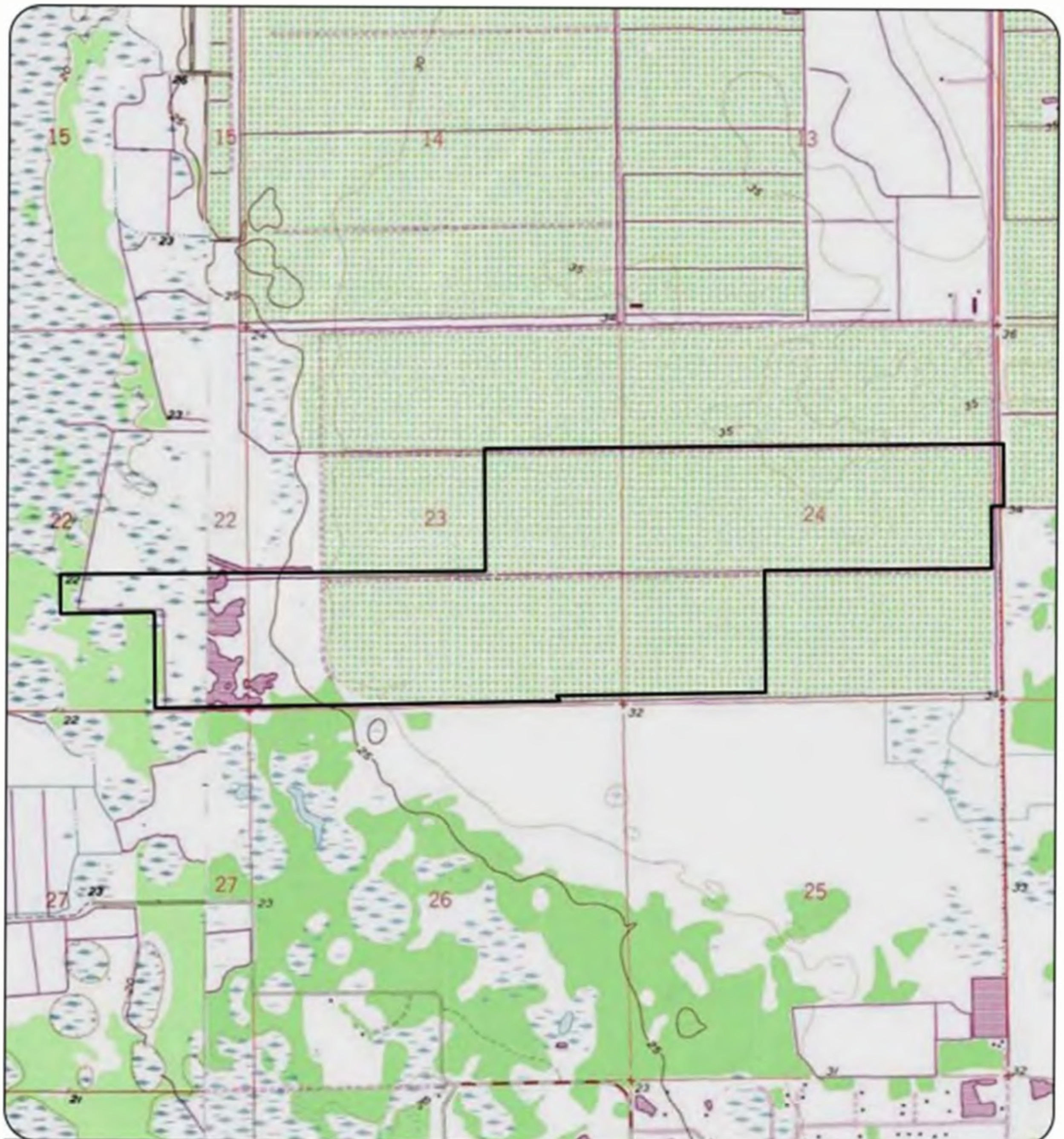
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

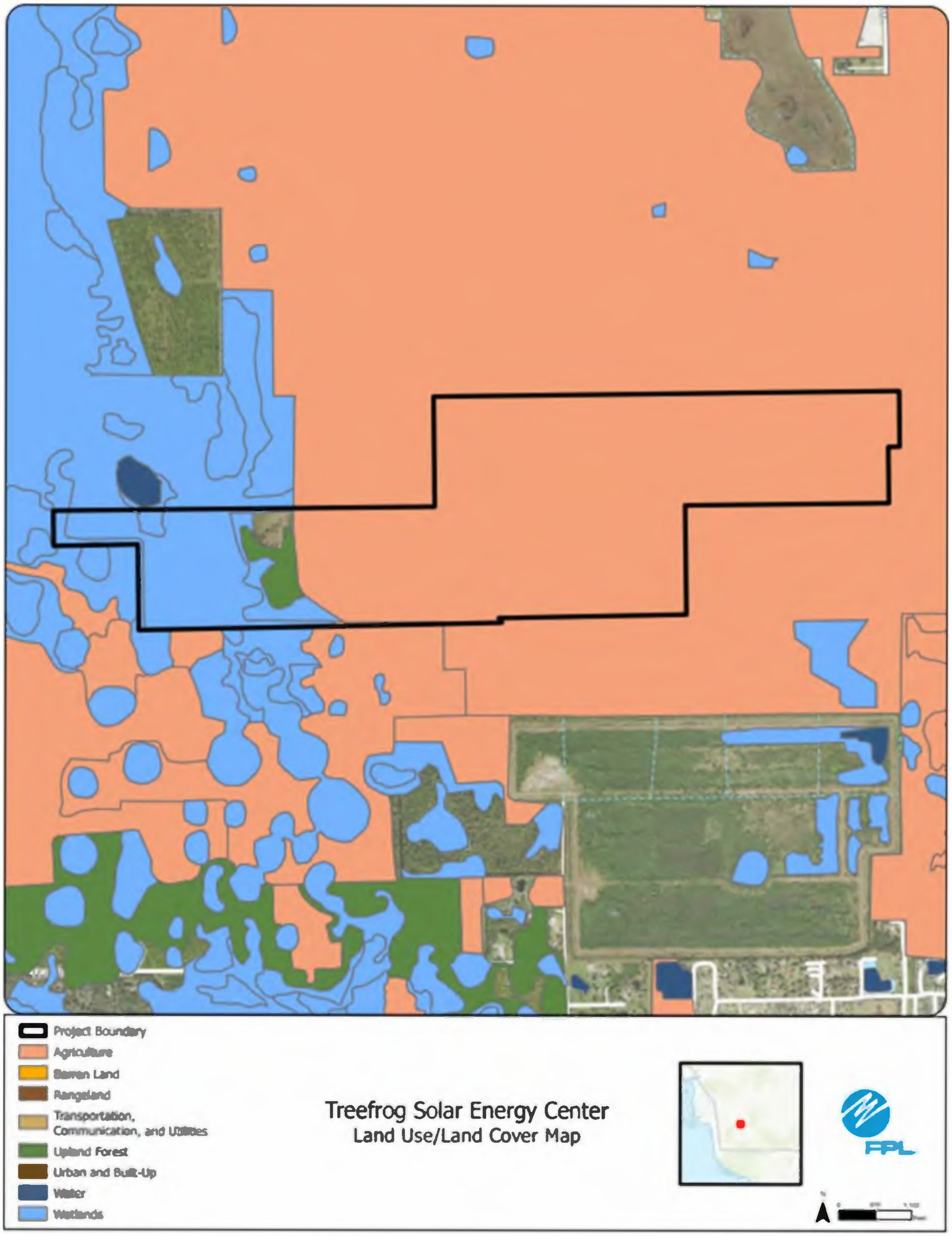
Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.



Treefrog Solar Energy Center

Treefrog Solar Energy Center
USGS Topography Map


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Treefrog Solar Energy Center
Land Use/Land Cover Map
FPL


Treefrog Solar Energy Center
Treefrog Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #7: Honeybee Branch Solar Energy Center

This potential site in Collier County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

The site and the surrounding area consist of various agricultural activities.

c. Environmental Features

Site is generally comprised of various agricultural areas and wetlands. Listed species in the vicinity of the project include the Audubon's crested caracara, Florida panther and gopher tortoise. No adverse impacts to listed species are anticipated. Corkscrew Swamp is located approximately 4,000 feet to the southwest.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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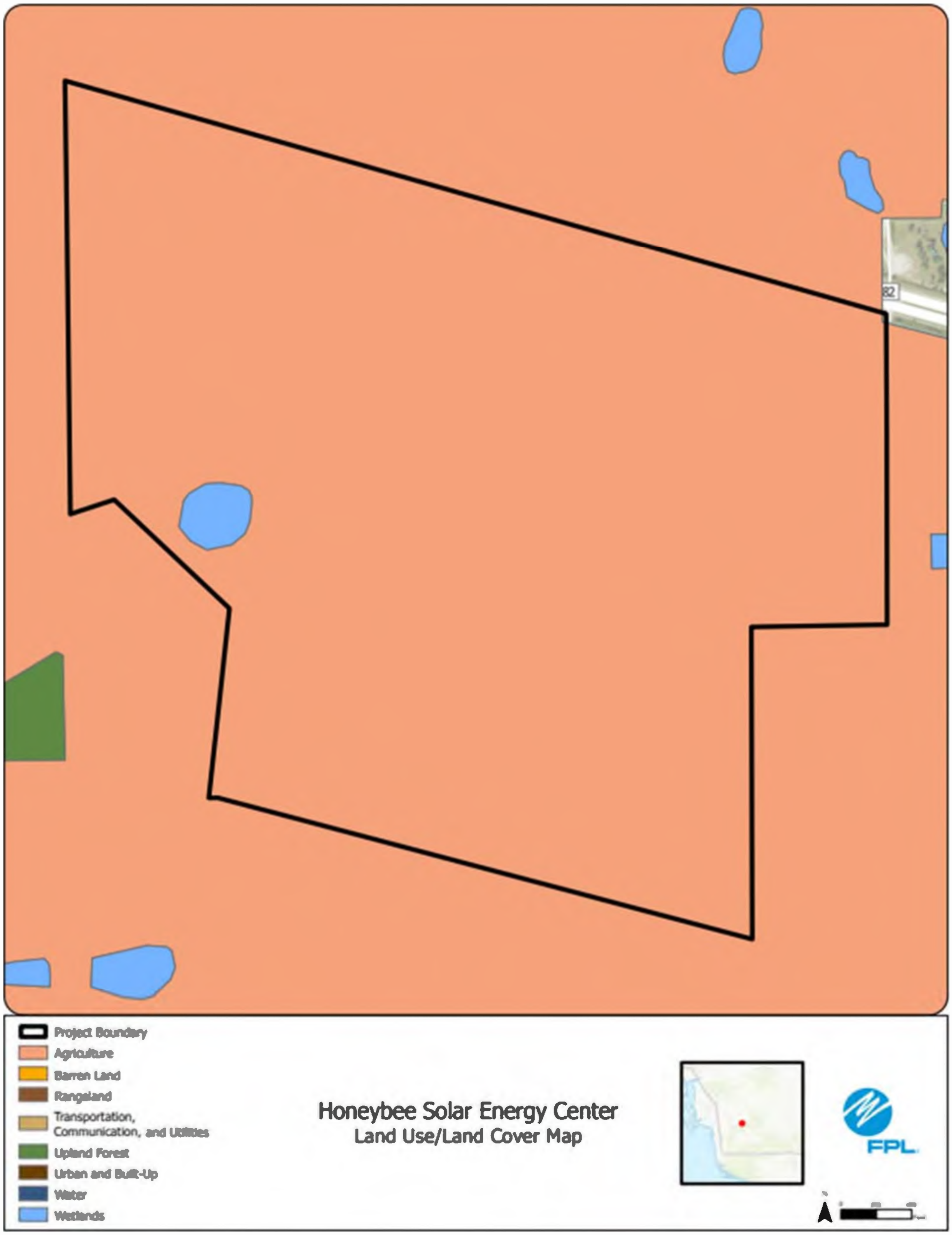
Honeybee Solar Energy Center
Honeybee Solar Energy Center
USGS Topography Map
FPL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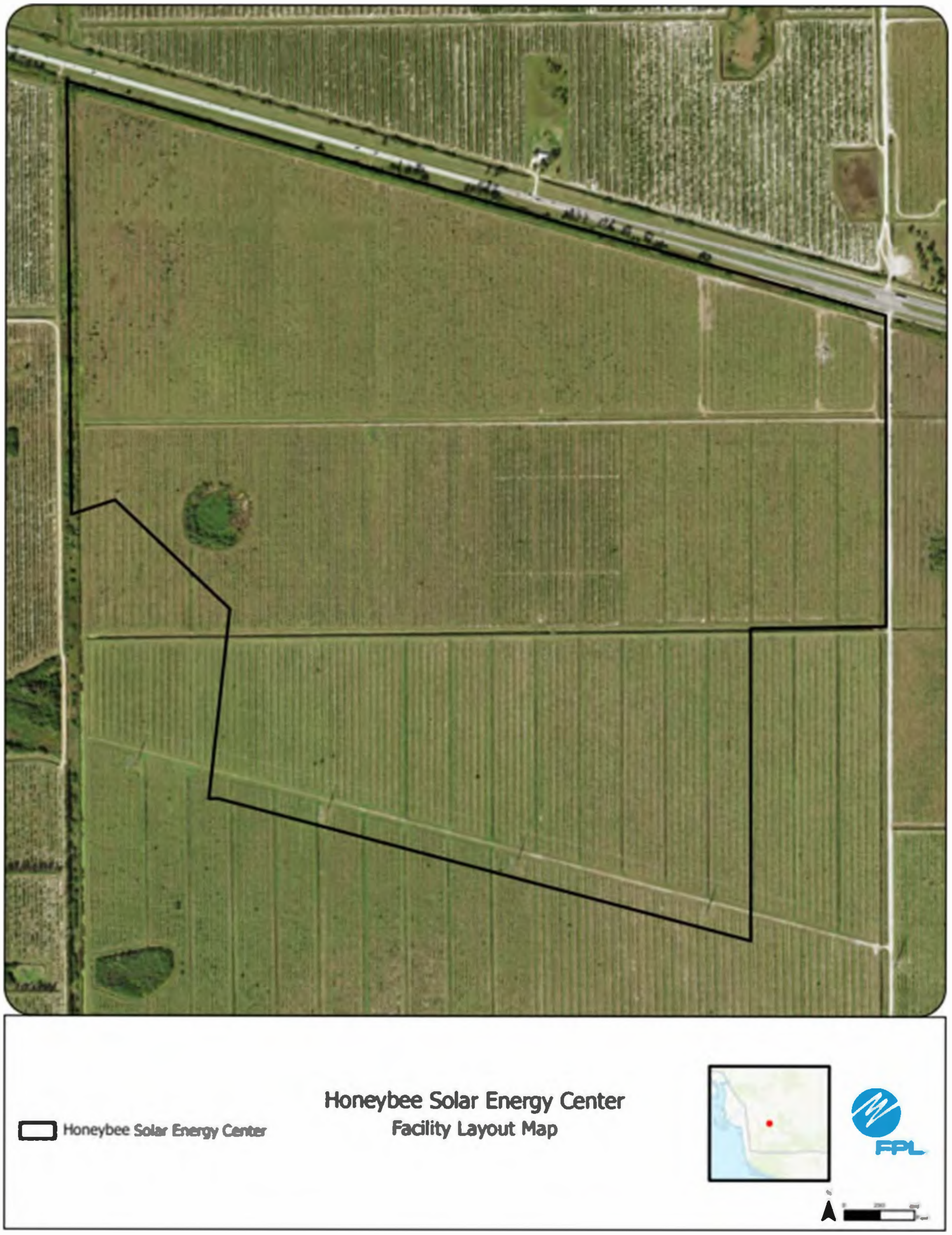
Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Honeybee Solar Energy Center
Land Use/Land Cover Map
FPL


Honeybee Solar Energy Center
Honeybee Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #8: Bromeliad Solar Energy Center

This potential site in Collier County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

The site and the surrounding area consist of various agricultural activities.

c. Environmental Features

Site is generally comprised of various agricultural areas and wetlands. Listed species in the vicinity of the project include the Audubon's crested caracara, Florida panther and gopher tortoise. No adverse impacts to listed species are anticipated. Corkscrew Swamp is located approximately 1,800 feet to the west.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

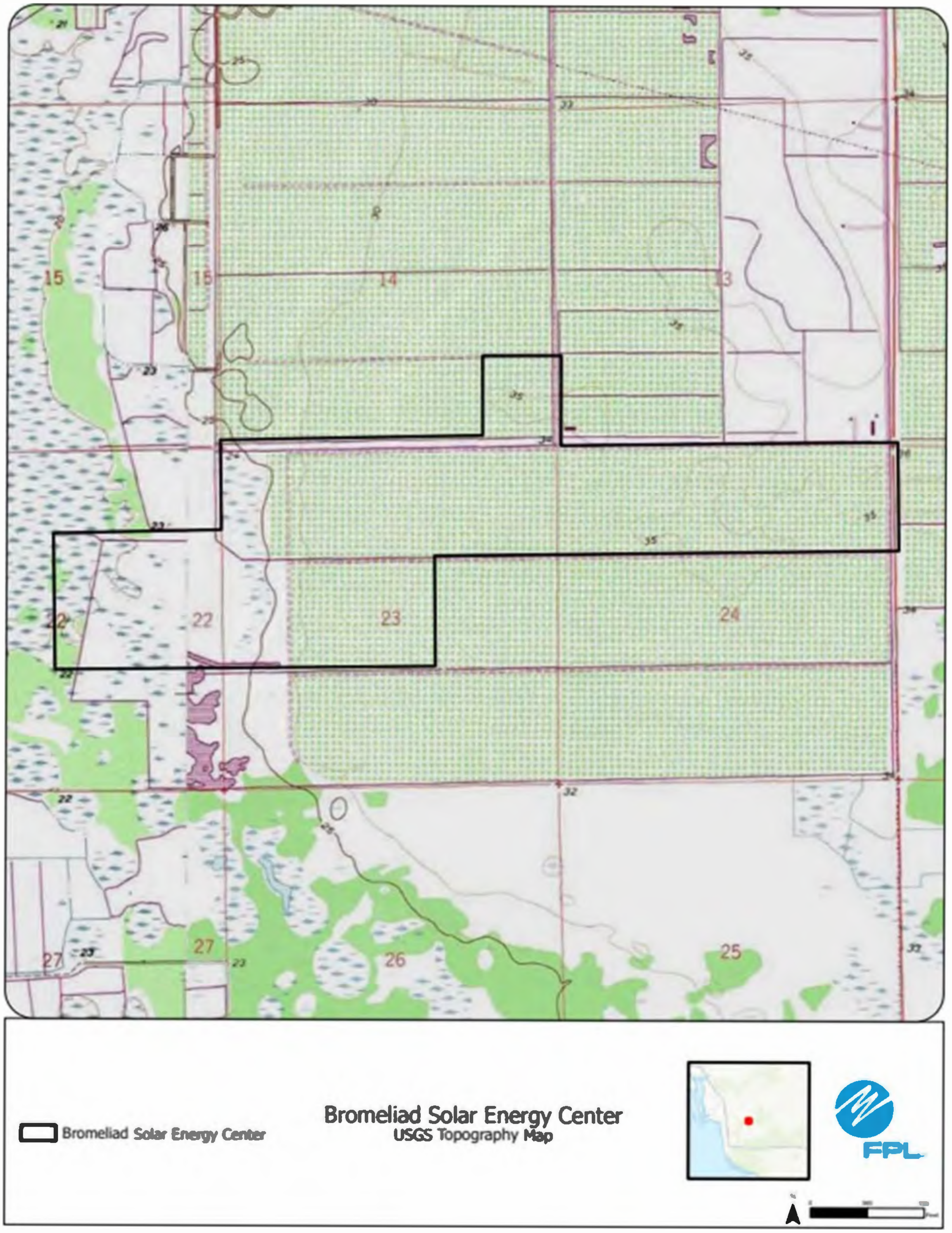
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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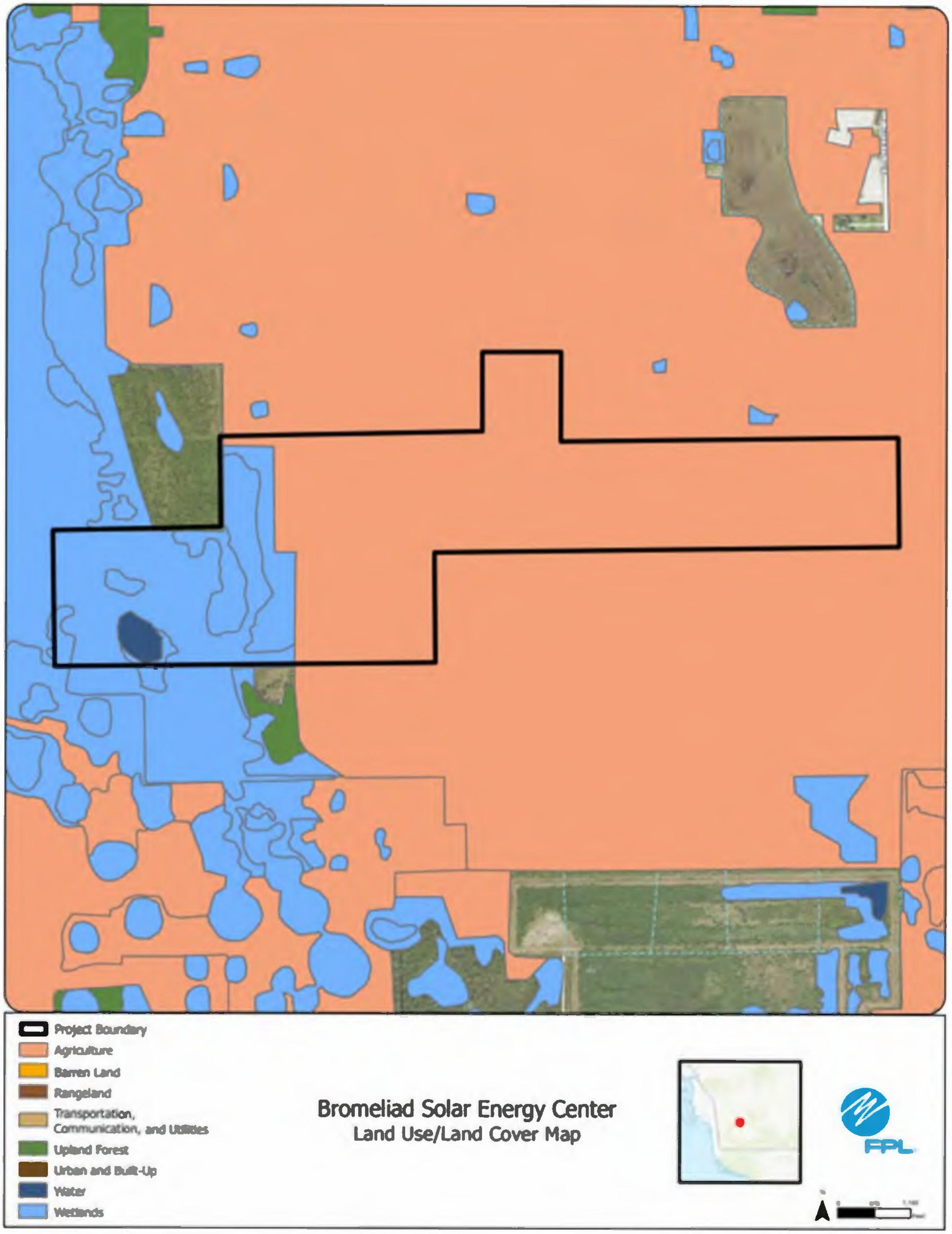
Bromeliad Solar Energy Center
Bromeliad Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Bromeliad Solar Energy Center
Land Use/Land Cover Map
FPL


Bromeliad Solar Energy Center
Bromeliad Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #9: Myakka Solar Energy Center

This potential site in Manatee County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site was formerly citrus and now consists of open fields with adjacent wetlands. Surrounding area is currently agricultural land and low-density residential areas.

c. Environmental Features

Site consists mainly of open fields with adjacent wetlands. Owens Branch is near the project. Listed species in the vicinity of the project include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

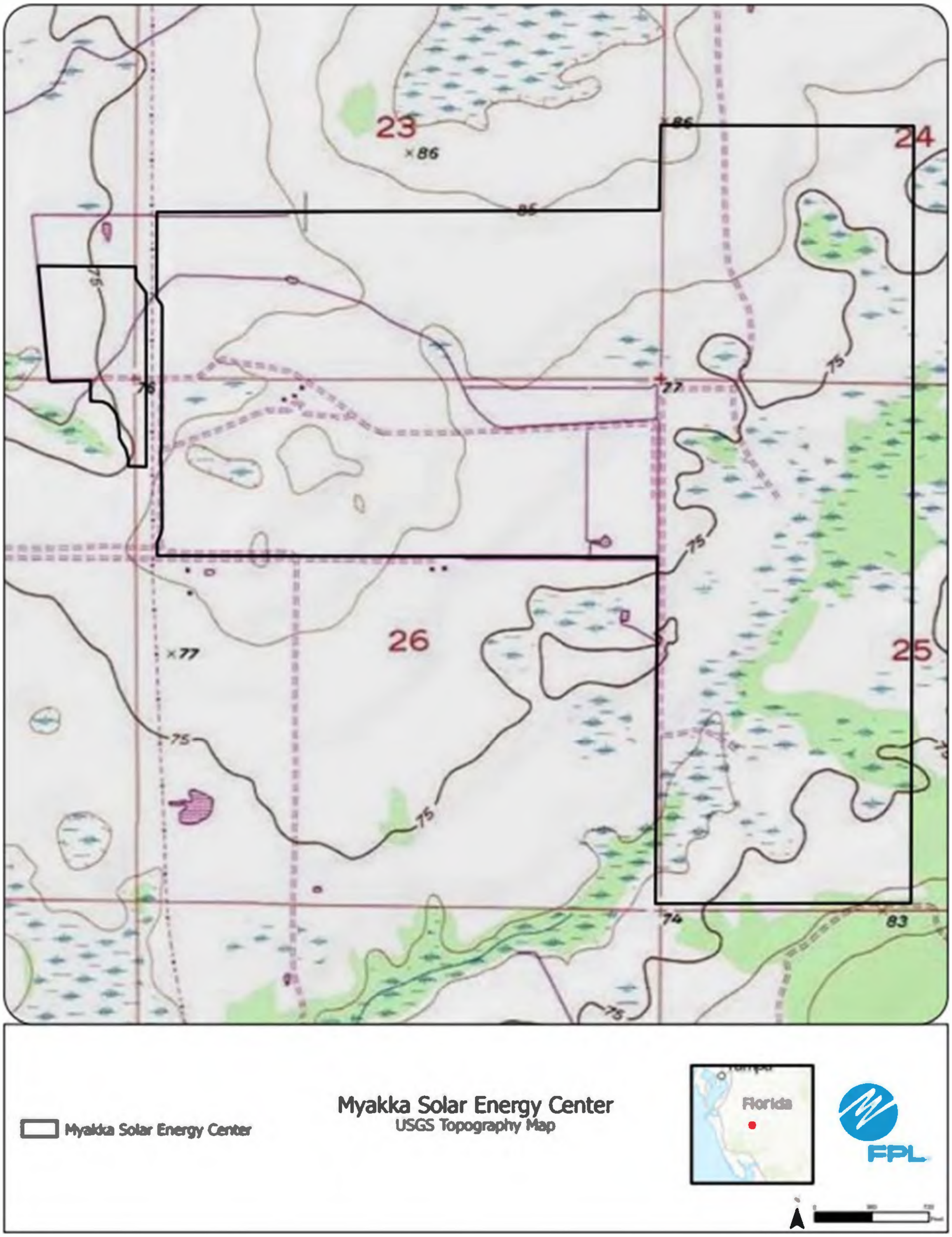
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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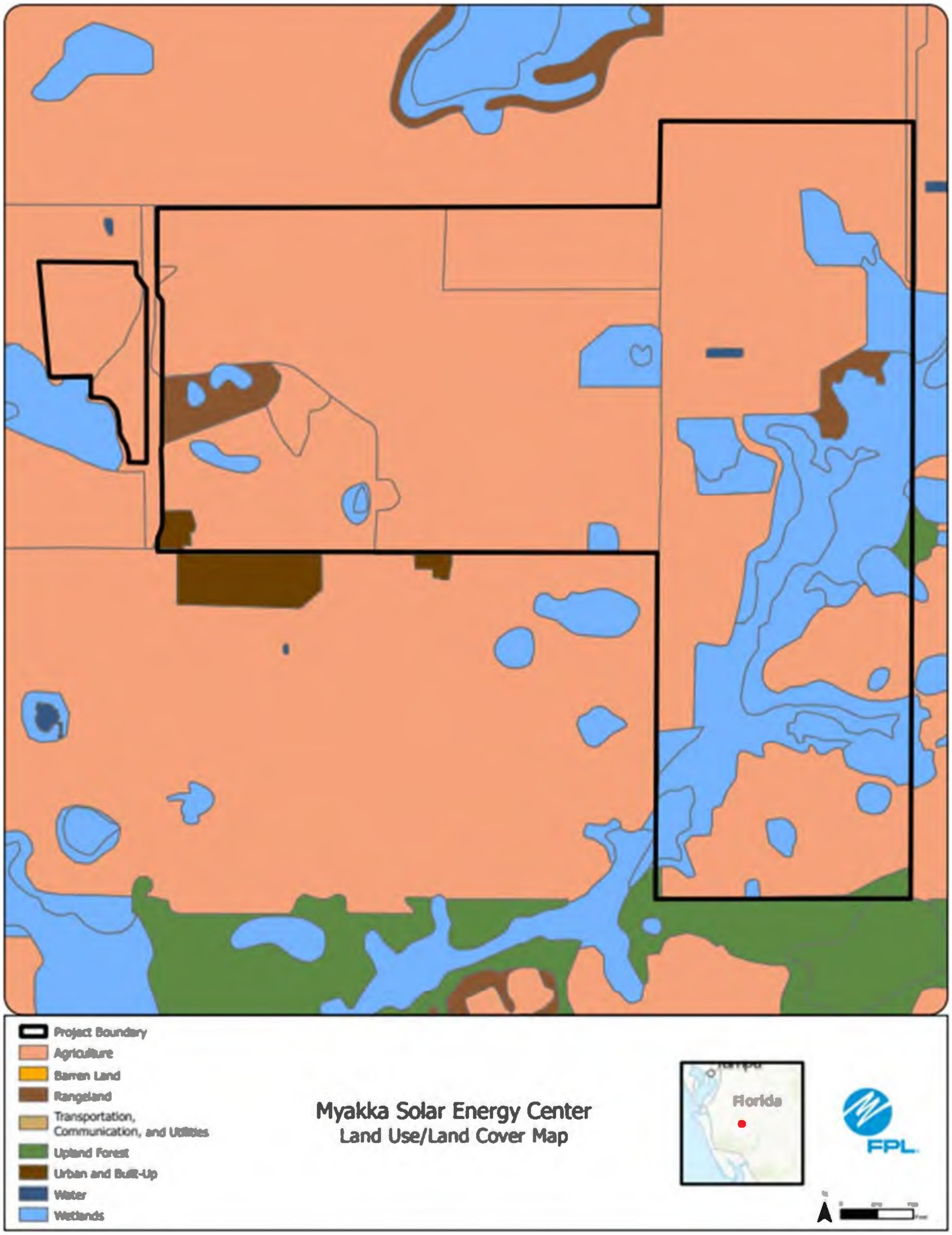
Myakka Solar Energy Center
Myakka Solar Energy Center
USGS Topography Map
Florida
FPL


Project Boundary
Agriculture
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Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Myakka Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Myakka Solar Energy Center
Myakka Solar Energy Center
Facility Layout Map
Florida
FPL

FPL Area Potential Site #10: Sand Gully Solar Energy Center

This potential site in DeSoto County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is improved pasture with agricultural ditches. Surrounding area includes various agricultural activities, agricultural ditches, canals and wetlands.

c. Environmental Features

Site is improved pasture with agricultural ditches. Listed species in the vicinity of the project include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

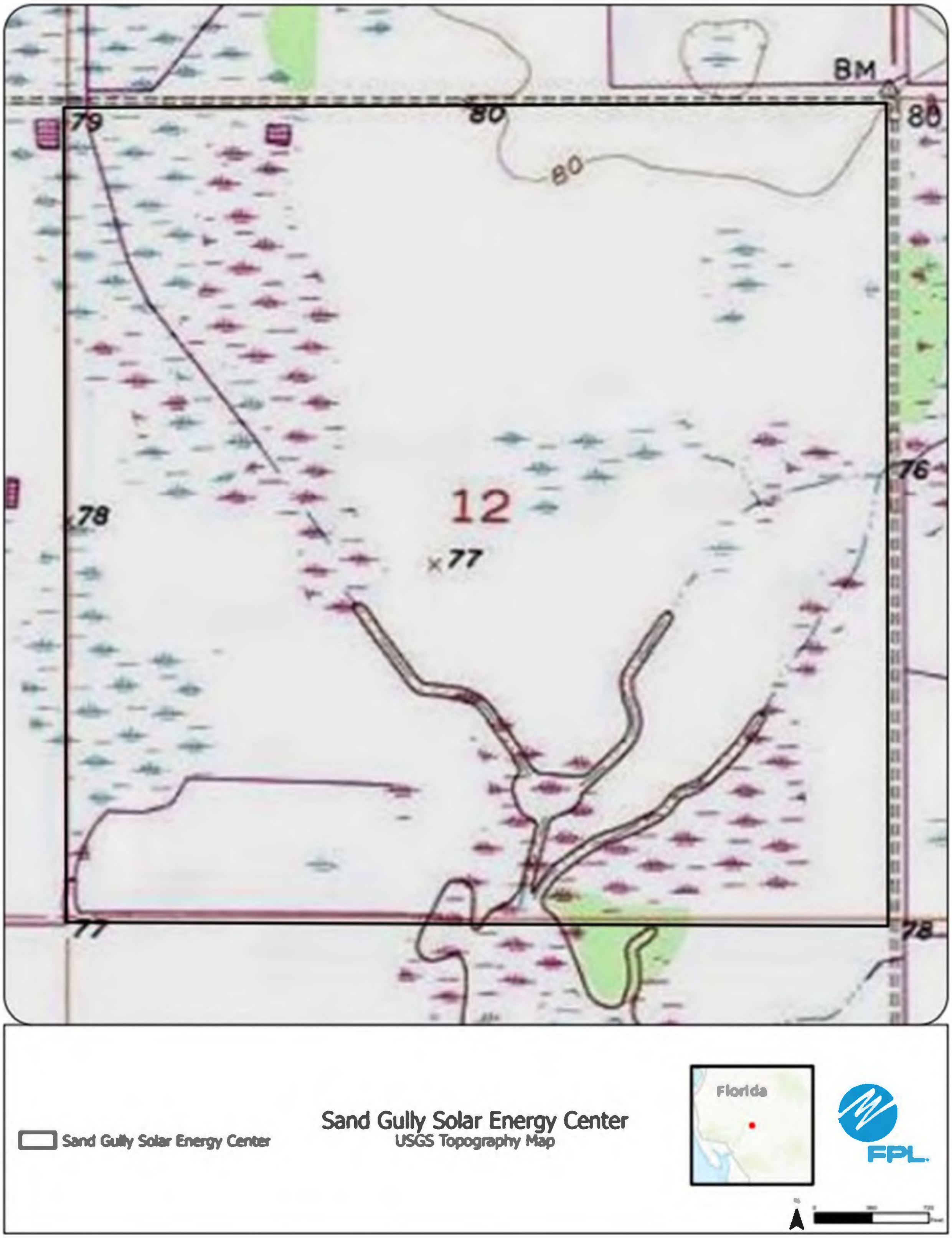
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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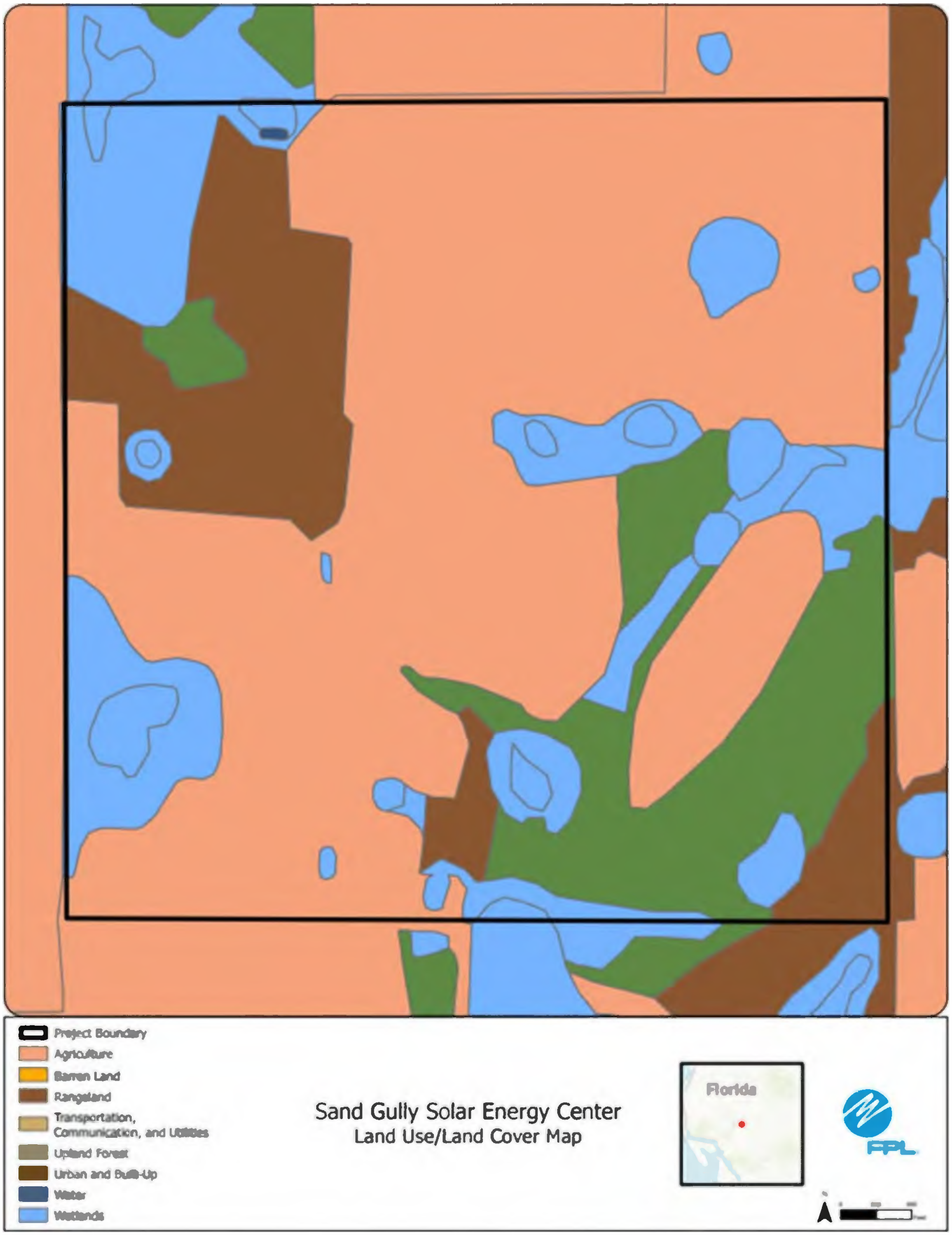
Sand Gully Solar Energy Center
Sand Gully Solar Energy Center
USGS Topography Map
Florida
FPL


Project Boundary
Agriculture
Barren Land
Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Sand Gully Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Sand Gully Solar Energy Center
Sand Gully Solar Energy Center
Facility Layout Map
Florida
FPL

FPL Area Potential Site #11: Gum Creek Solar Energy Center

This potential site in Jackson County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is primarily silviculture and wetlands. Surrounding area includes agricultural lands, silviculture operations and residential properties.

c. Environmental Features

Site is primarily silviculture and wetlands. Listed species observed during the general wildlife survey were limited to gopher tortoise.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

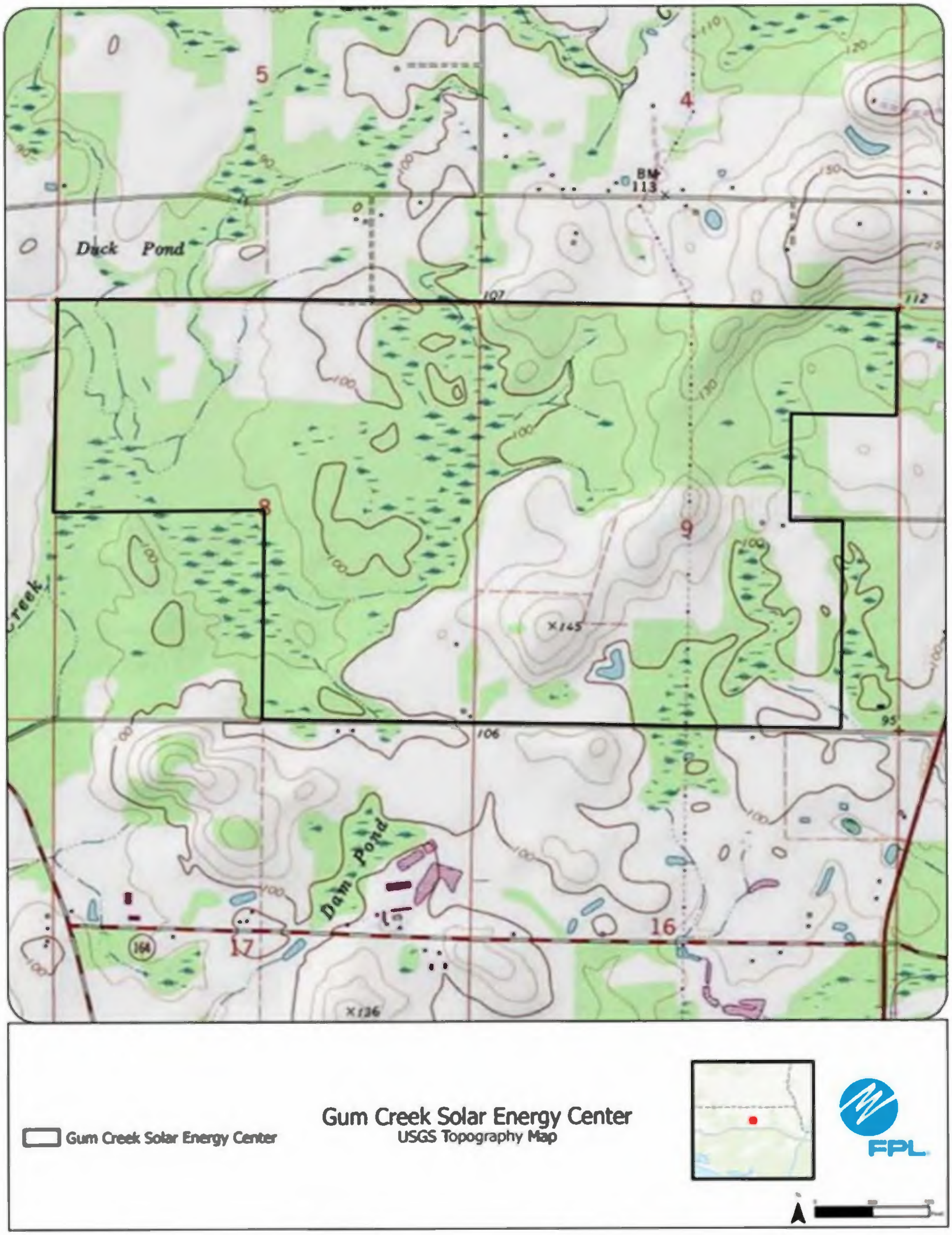
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

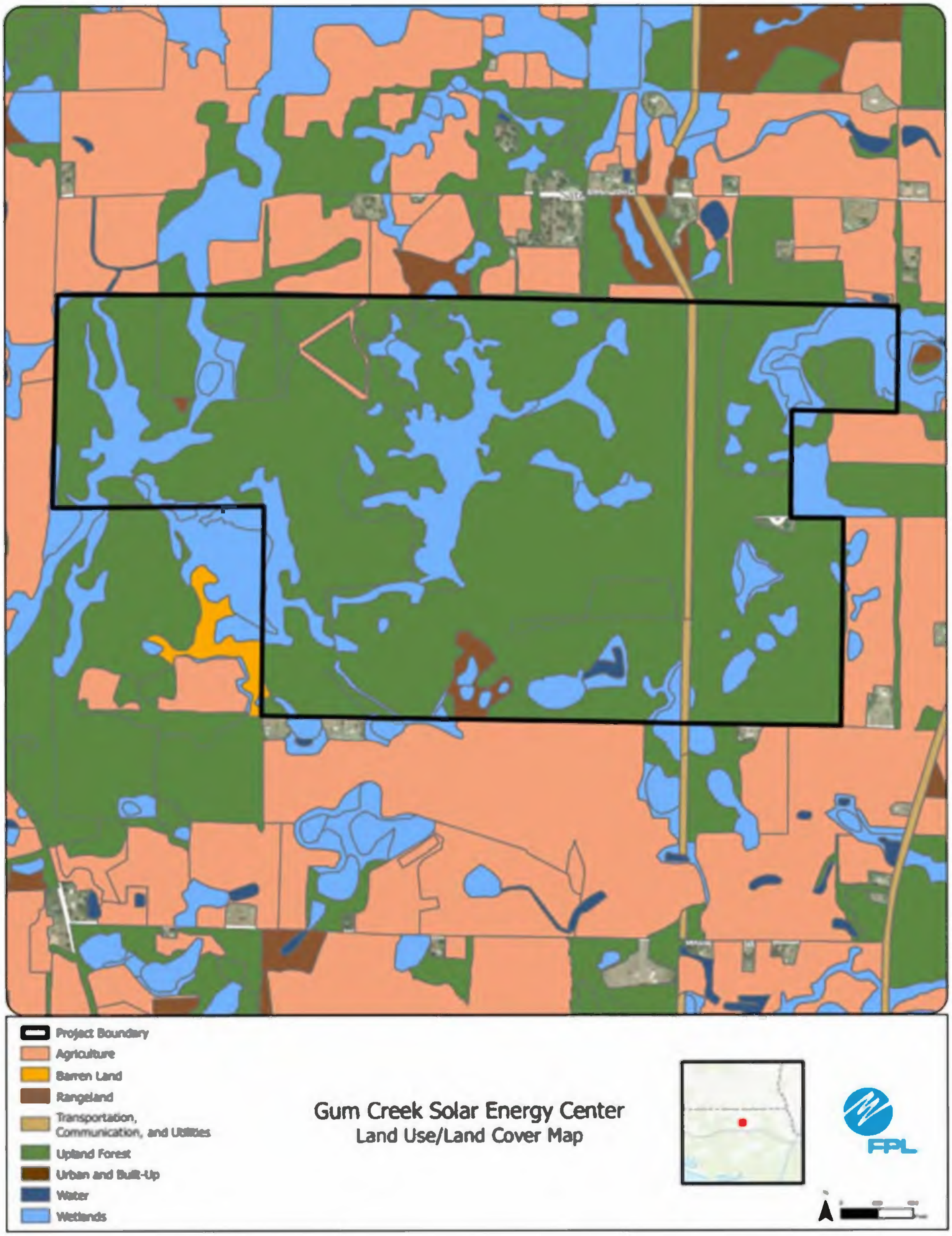
e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.


Duck Pond
Dam Pond
Creek
BM 113
Gum Creek Solar Energy Center
Gum Creek Solar Energy Center
USGS Topography Map
FPL


Project Boundary
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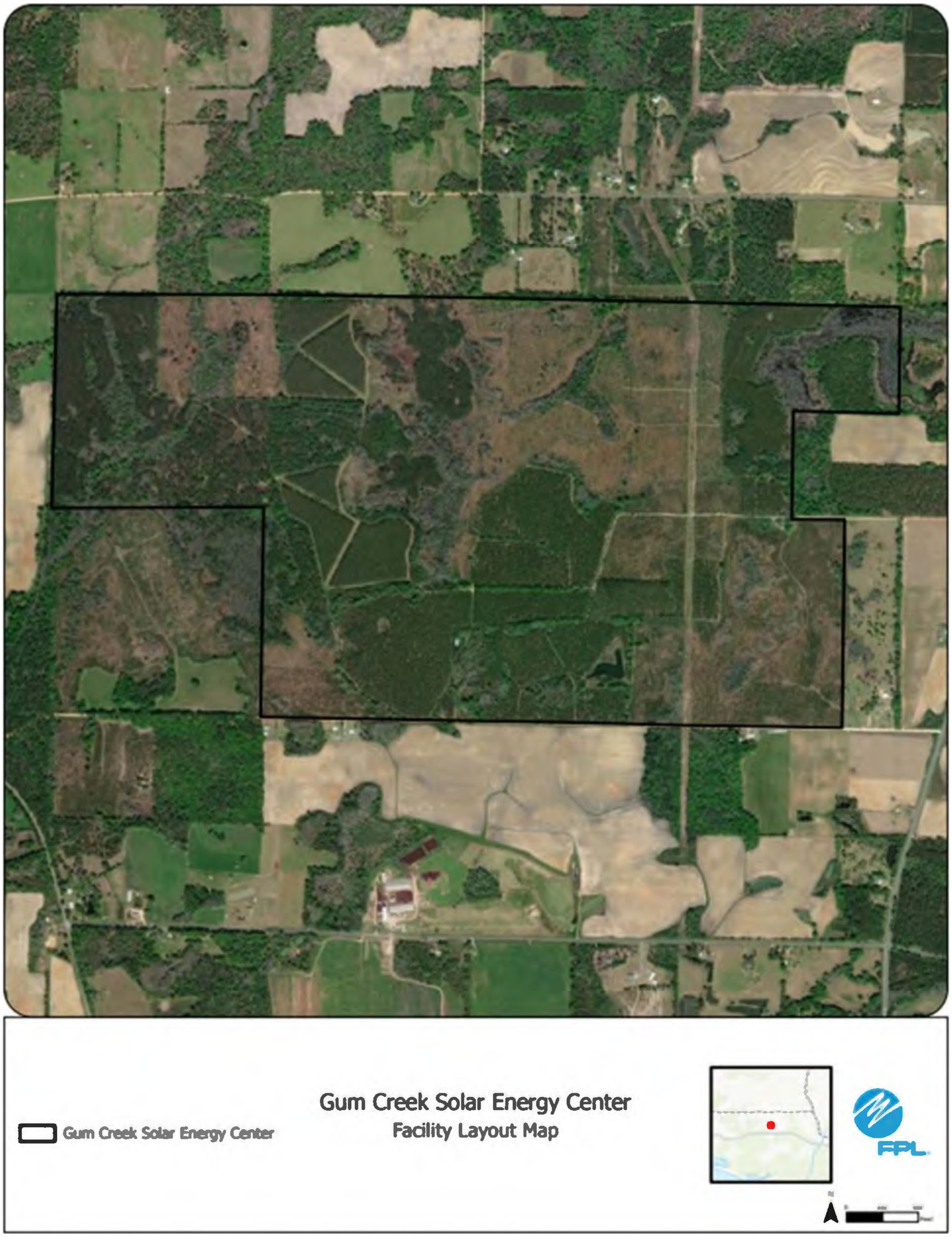
Gum Creek Solar Energy Center
Land Use/Land Cover Map
FPL


Gum Creek Solar Energy Center
Gum Creek Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #12: Cardinal Solar Energy Center

This potential site in Brevard County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site and adjoining properties consist of agricultural lands, wetlands, and reservoirs.

c. Environmental Features

Site is agricultural. An Audubon's crested caracara nest was identified approximately 2000 feet to the east on the adjoining property. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

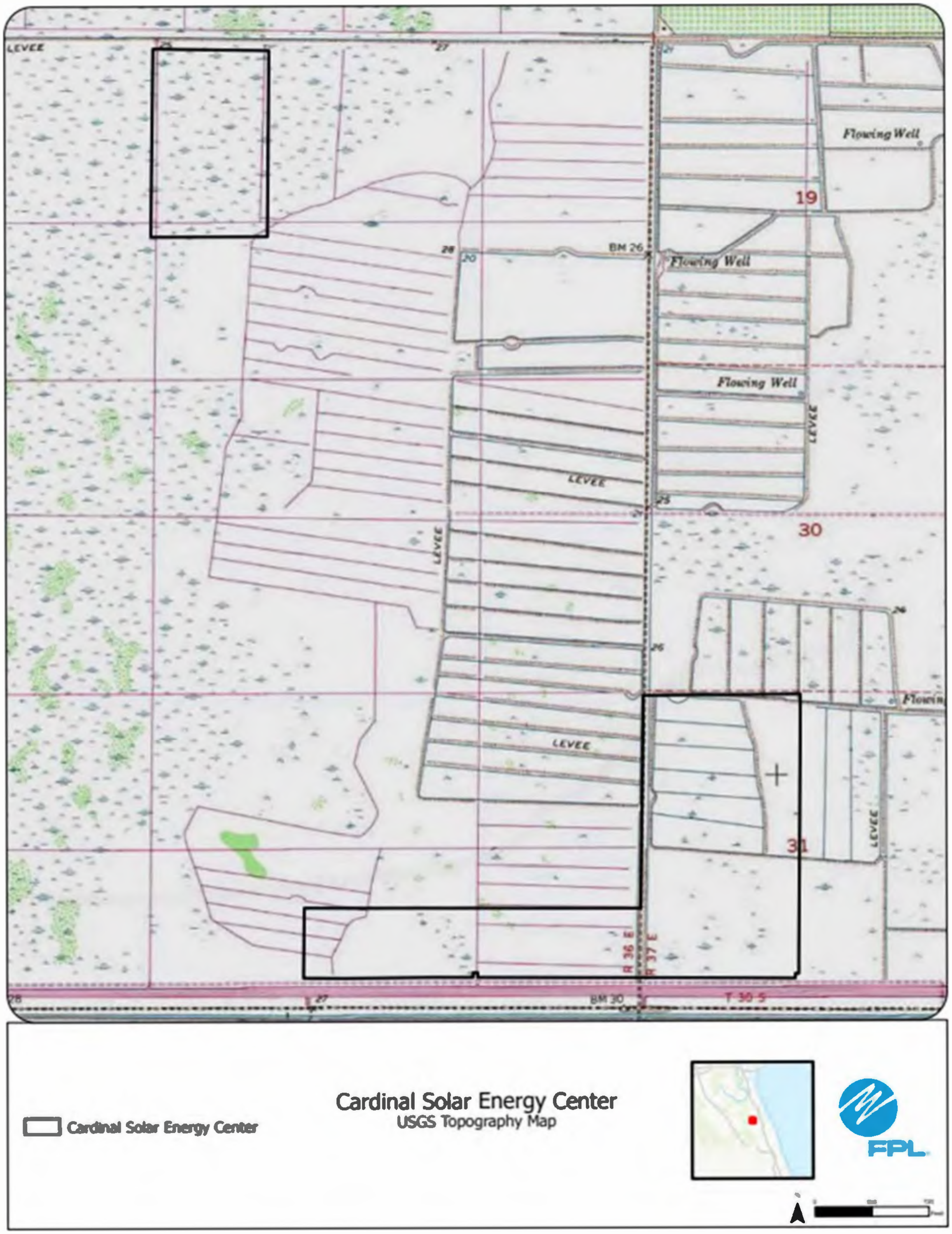
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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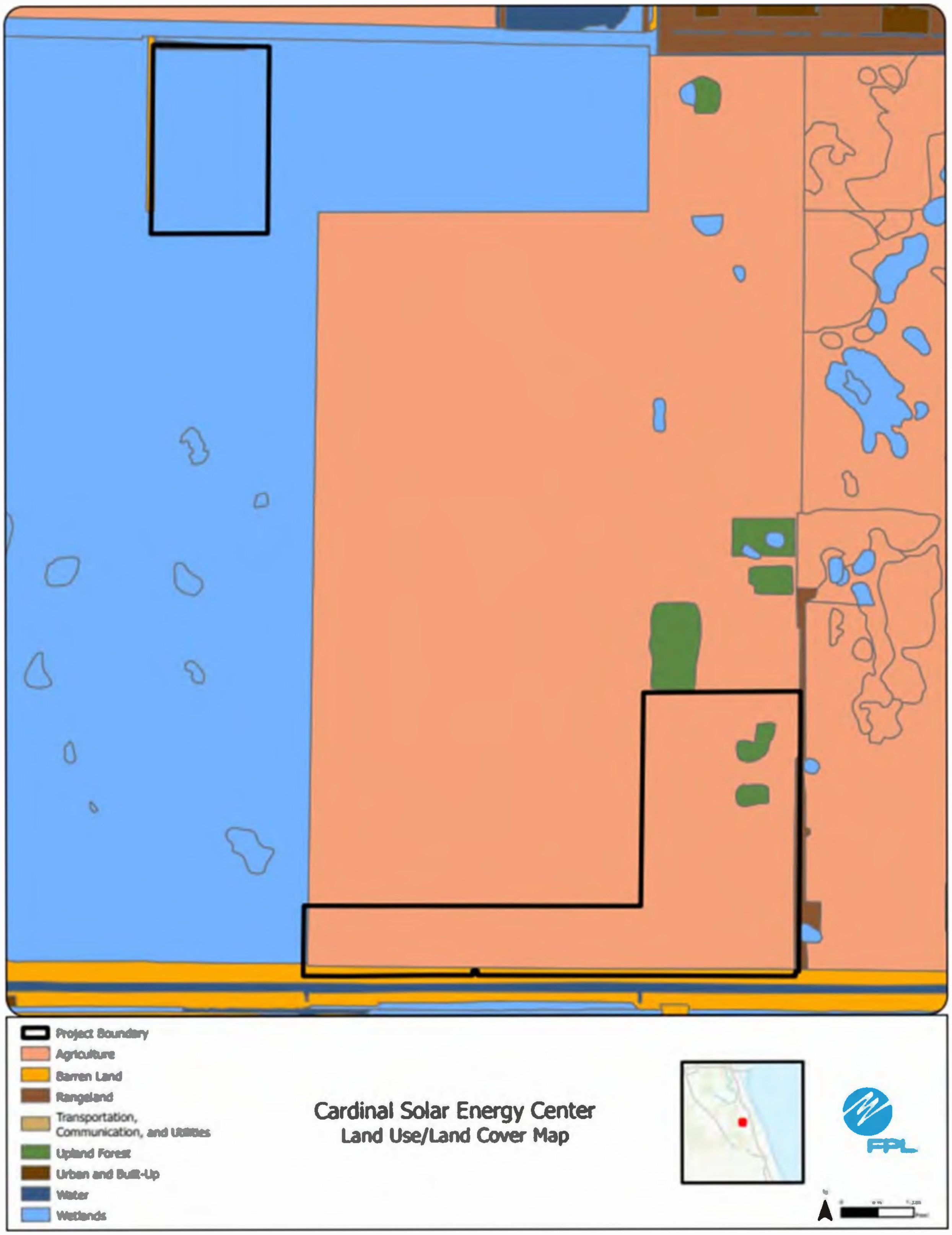
Cardinal Solar Energy Center
Cardinal Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
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Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Cardinal Solar Energy Center
Land Use/Land Cover Map
FPL


Cardinal Solar Energy Center
Cardinal Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #13: Pine Lily Solar Energy Center

This potential site in St. Lucie County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is active citrus with agricultural ditches and natural wetlands. Adjacent properties include citrus, ditches, and wetlands.

c. Environmental Features

The site is dominated by active citrus groves with agricultural ditches and some natural wetlands. Listed species in the vicinity of the project include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.


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SPOIL BANK
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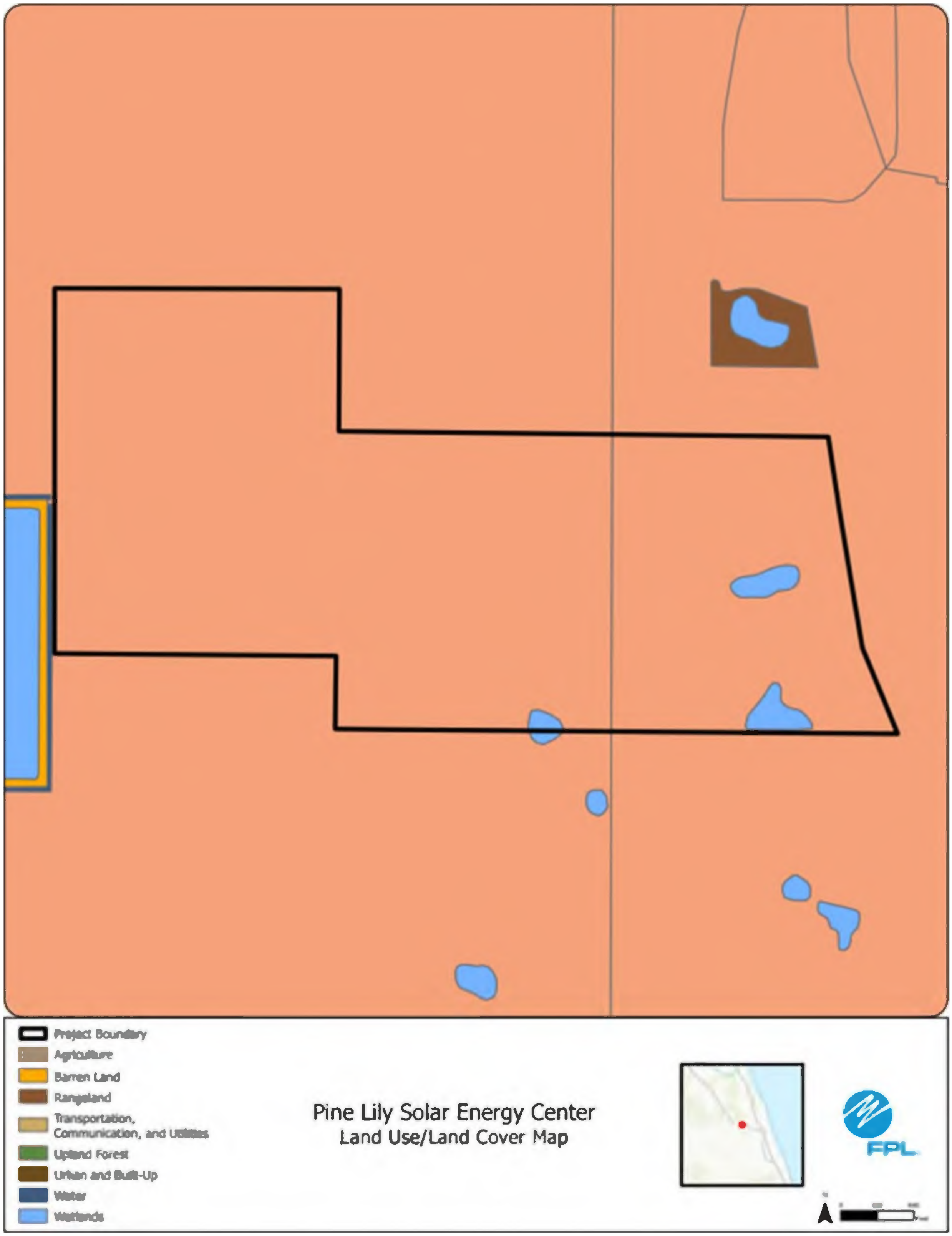
Pine Lily Solar Energy Center
Pine Lily Solar Energy Center
USGS Topography Map
FPL


Project Boundary
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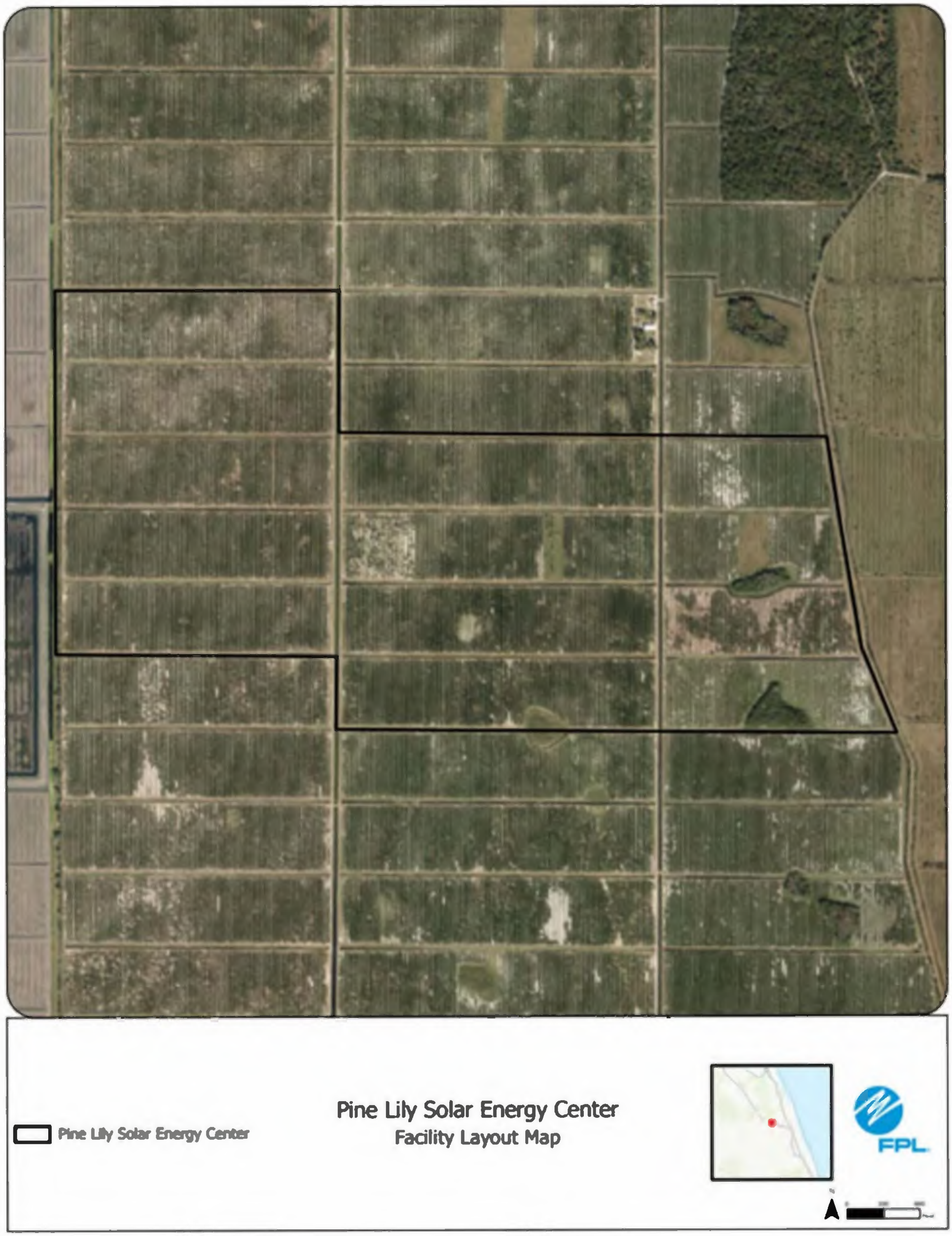
Upland Forest
Urban and Built-Up
Water
Wetlands
Pine Lily Solar Energy Center
Land Use/Land Cover Map
FPL


Pine Lily Solar Energy Center
Pine Lily Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #14: Wild Lime Solar Energy Center

This potential site in St. Lucie County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is active citrus and improved pasture with agricultural ditches and natural wetlands. Adjacent properties include citrus, ditches, and wetlands.

c. Environmental Features

The site is dominated by active citrus groves, improved pasture, agricultural ditches and some natural wetlands. Listed species in the vicinity of the project include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

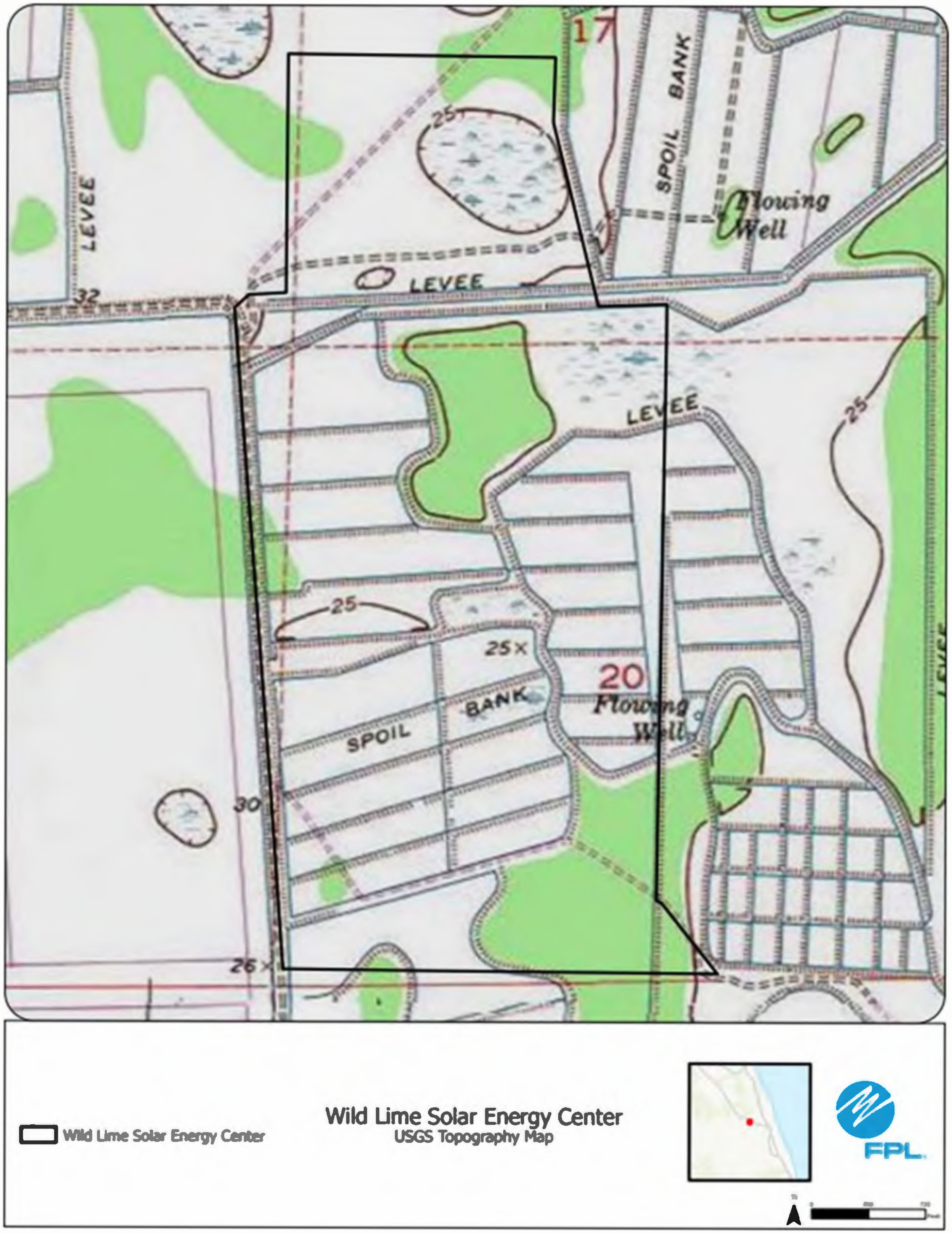
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.


17
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SPOIL BANK
Flowing Well
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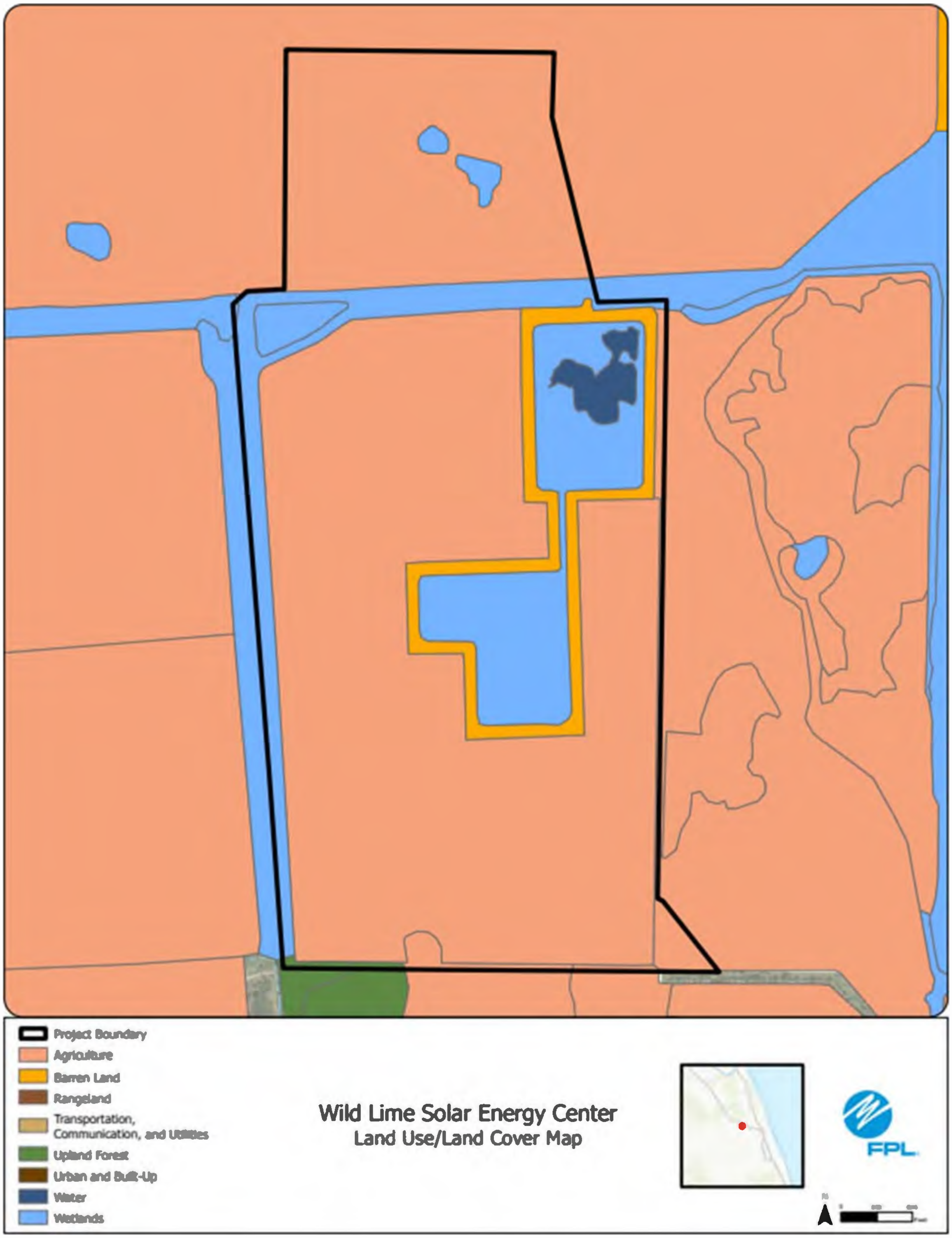
LEVEE
Wild Lime Solar Energy Center
Wild Lime Solar Energy Center
USGS Topography Map
FPL


Project Boundary
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Upland Forest
Urban and Built-Up
Water
Wetlands
Wild Lime Solar Energy Center
Land Use/Land Cover Map
FPL

Wild Lime Solar Energy Center
Facility Layout Map

FPL Area Potential Site #15: Spoonbill Solar Energy Center

This potential site in Collier County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

The site and the surrounding area consist of various agricultural activities.

c. Environmental Features

Site is generally comprised of various agricultural areas and wetlands. Listed species in the vicinity of the project include the Audubon's crested caracara, Florida panther and gopher tortoise. No adverse impacts to listed species are anticipated. Corkscrew Swamp is located approximately 3,000 feet to the west.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

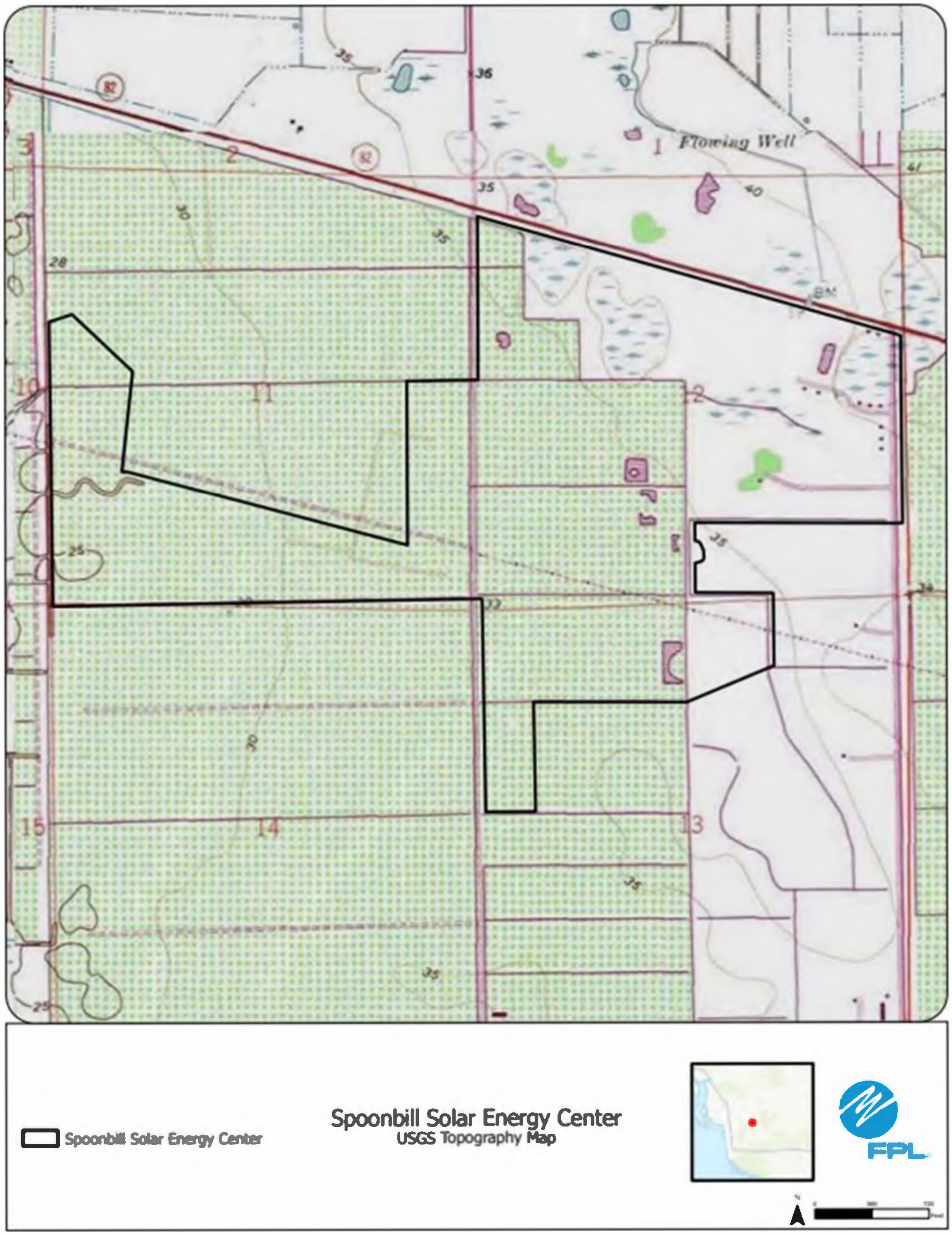
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

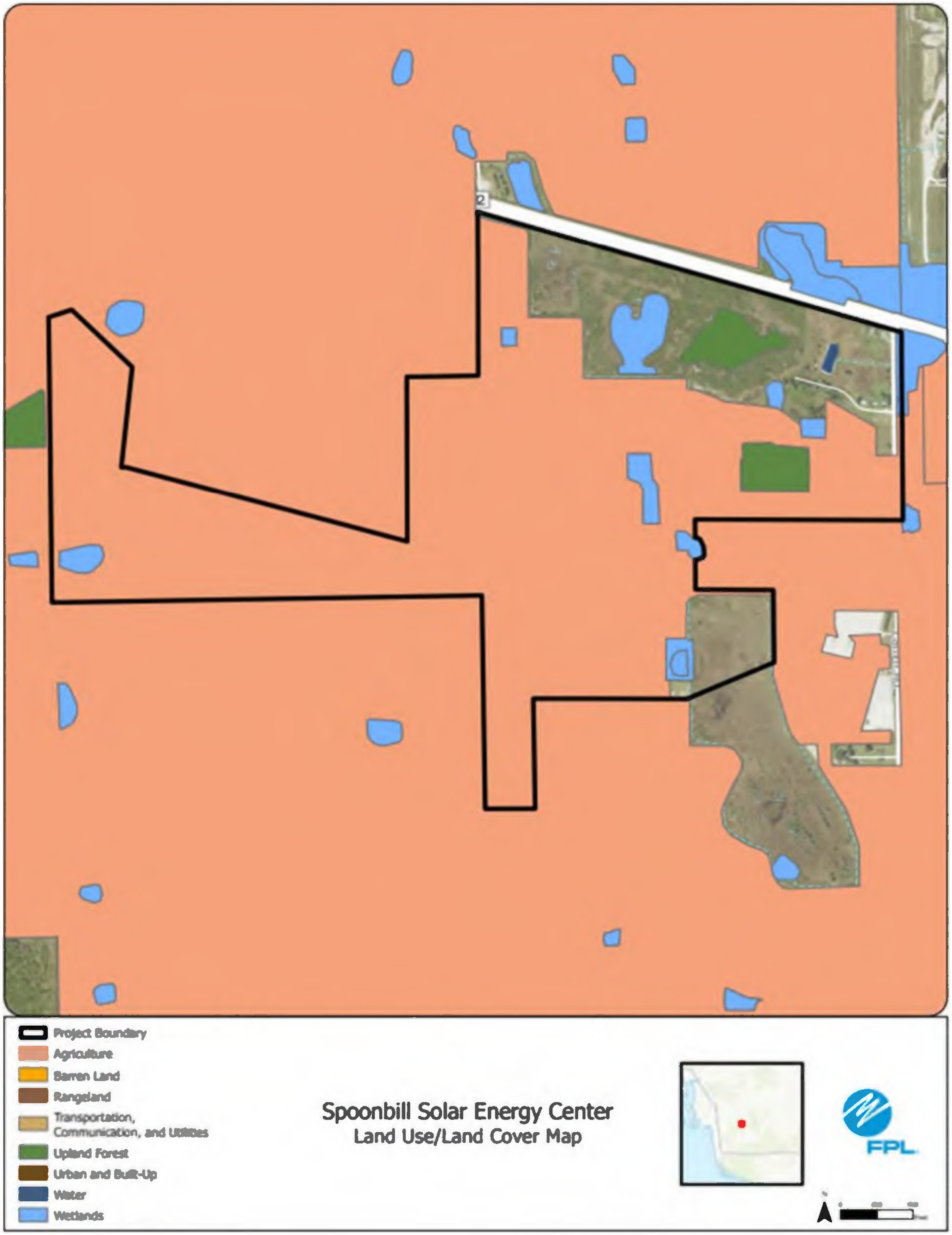
e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.


Flowing Well
Spoonbill Solar Energy Center
Spoonbill Solar Energy Center
USGS Topography Map
FPL


Project Boundary
Agriculture
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Rangeland
Transportation, Communication, and Utilities
Upland Forest
Urban and Built-Up
Water
Wetlands
Spoonbill Solar Energy Center
Land Use/Land Cover Map
FPL


Spoonbill Solar Energy Center
Spoonbill Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #16: Shell Creek Solar Energy Center

This potential site in Charlotte and DeSoto Counties is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

The site and the surrounding area consist of various agricultural areas, pasture, and wetlands.

c. Environmental Features

Site is generally comprised of various agricultural areas. Listed species in the vicinity of the project include Audubon's crested caracara and gopher tortoise. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

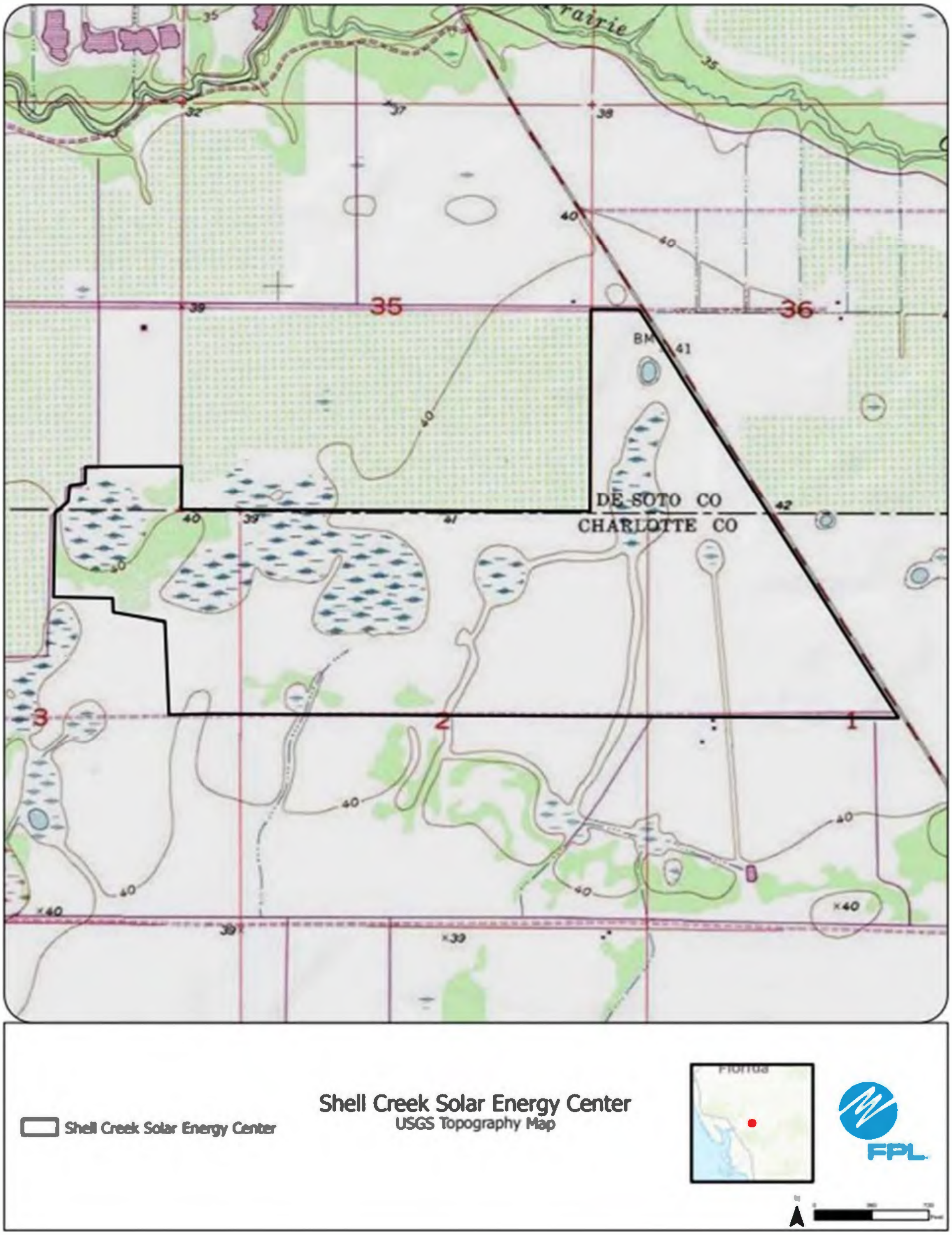
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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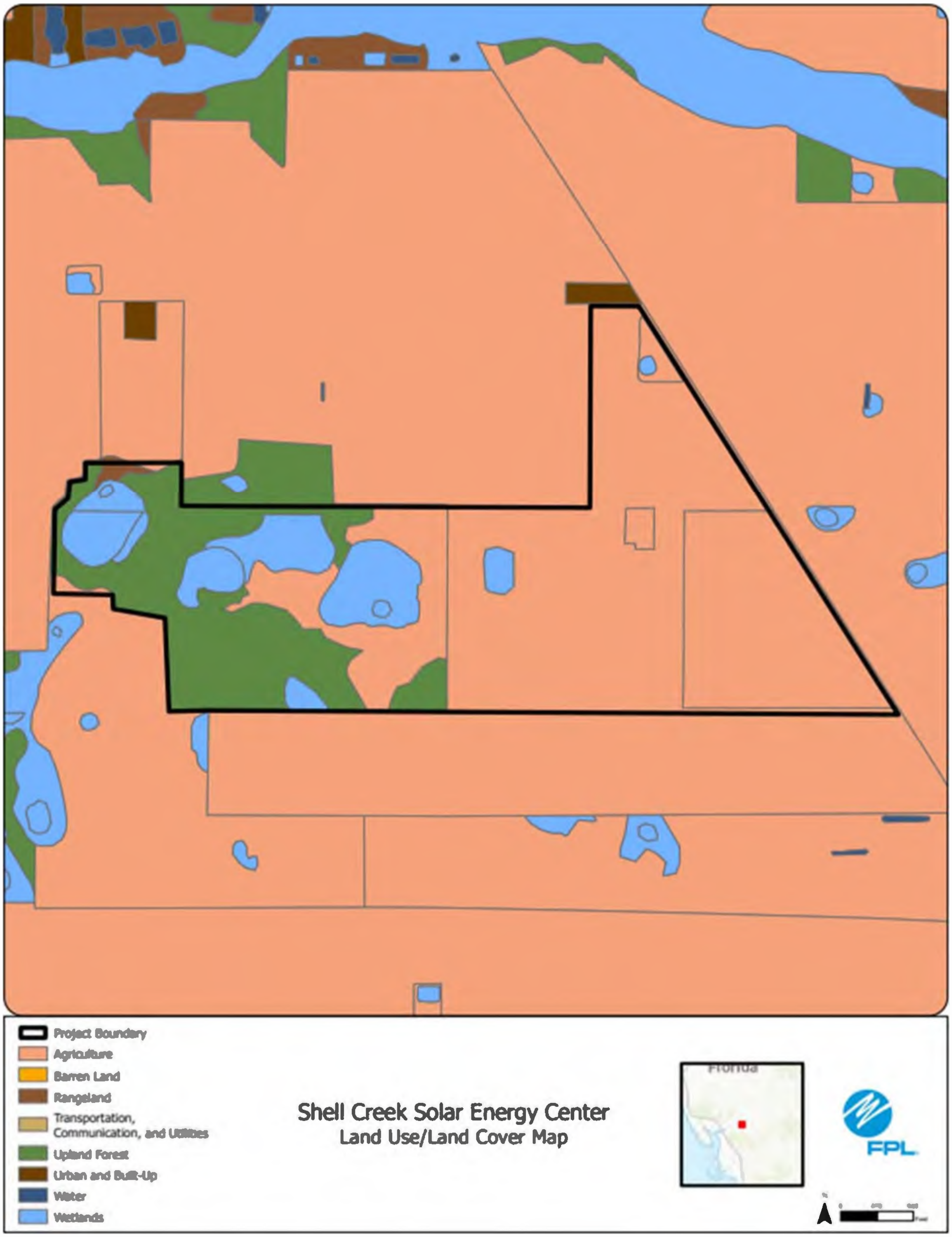
CHARLOTTE CO
Shell Creek Solar Energy Center
Shell Creek Solar Energy Center
USGS Topography Map
FPL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Urban and Built-Up
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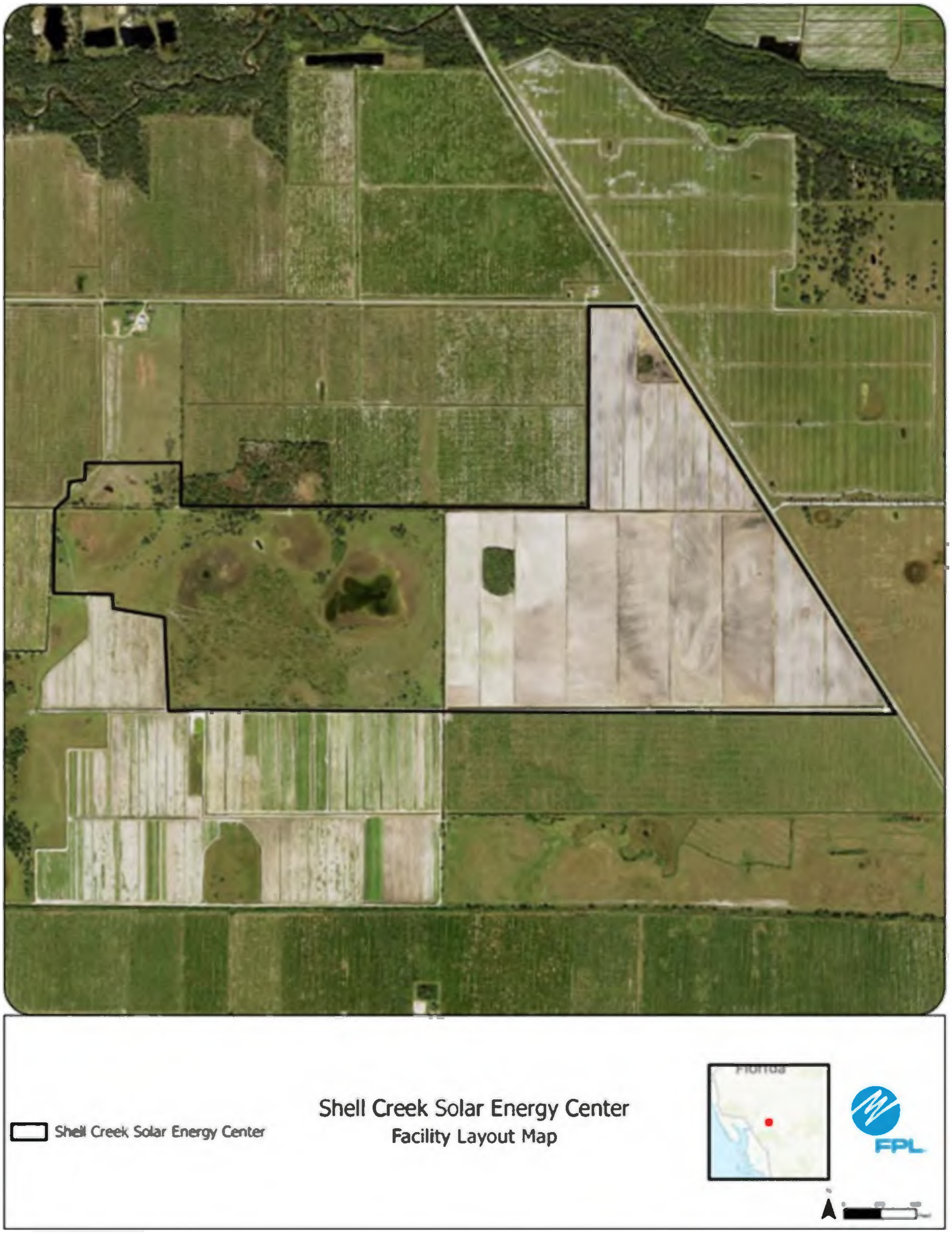
Shell Creek Solar Energy Center
Land Use/Land Cover Map
Florida
FPL


Shell Creek Solar Energy Center
Shell Creek Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #17: Carlton Solar Energy Center

This potential site in St. Lucie County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site is improved pasture with agricultural ditches. Surrounding area is used for various agricultural purposes.

c. Environmental Features

Site is improved pasture surrounded by agricultural ditches. The County Line Canal is west of the property. Listed species in the vicinity of the project include Audubon's crested caracara and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

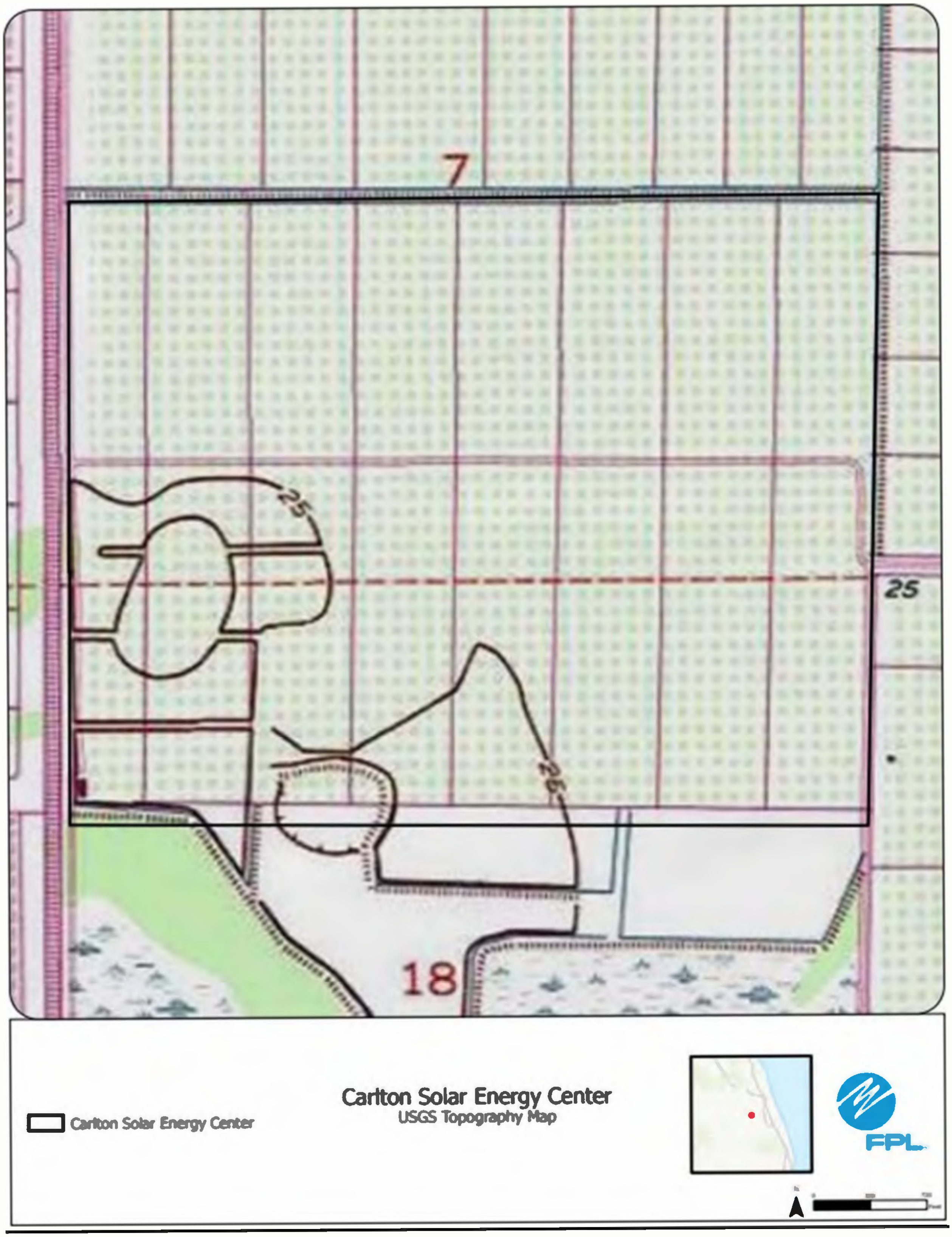
Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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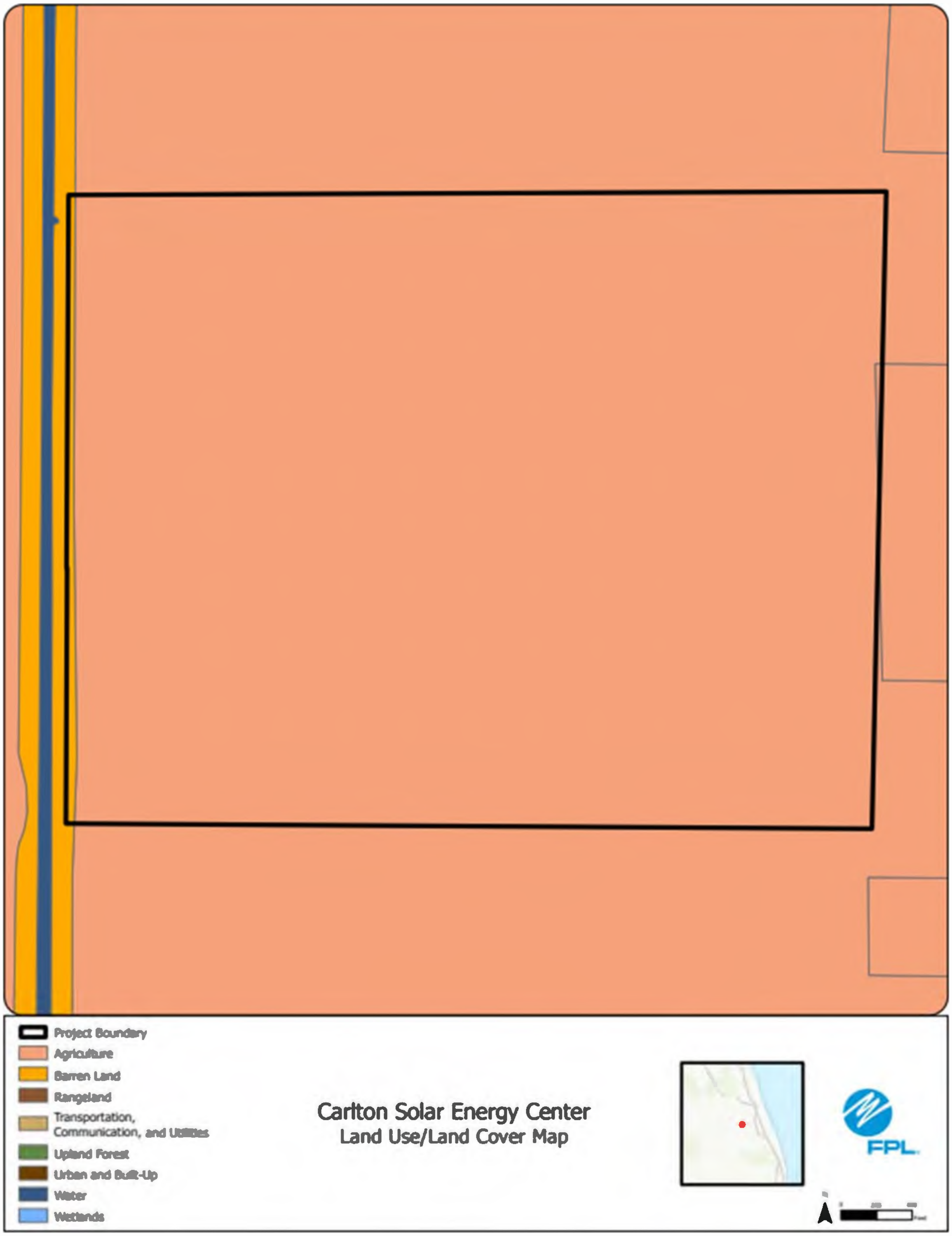
Carlton Solar Energy Center
Carlton Solar Energy Center
USGS Topography Map
FPL


Project Boundary
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Upland Forest
Urban and Built-Up
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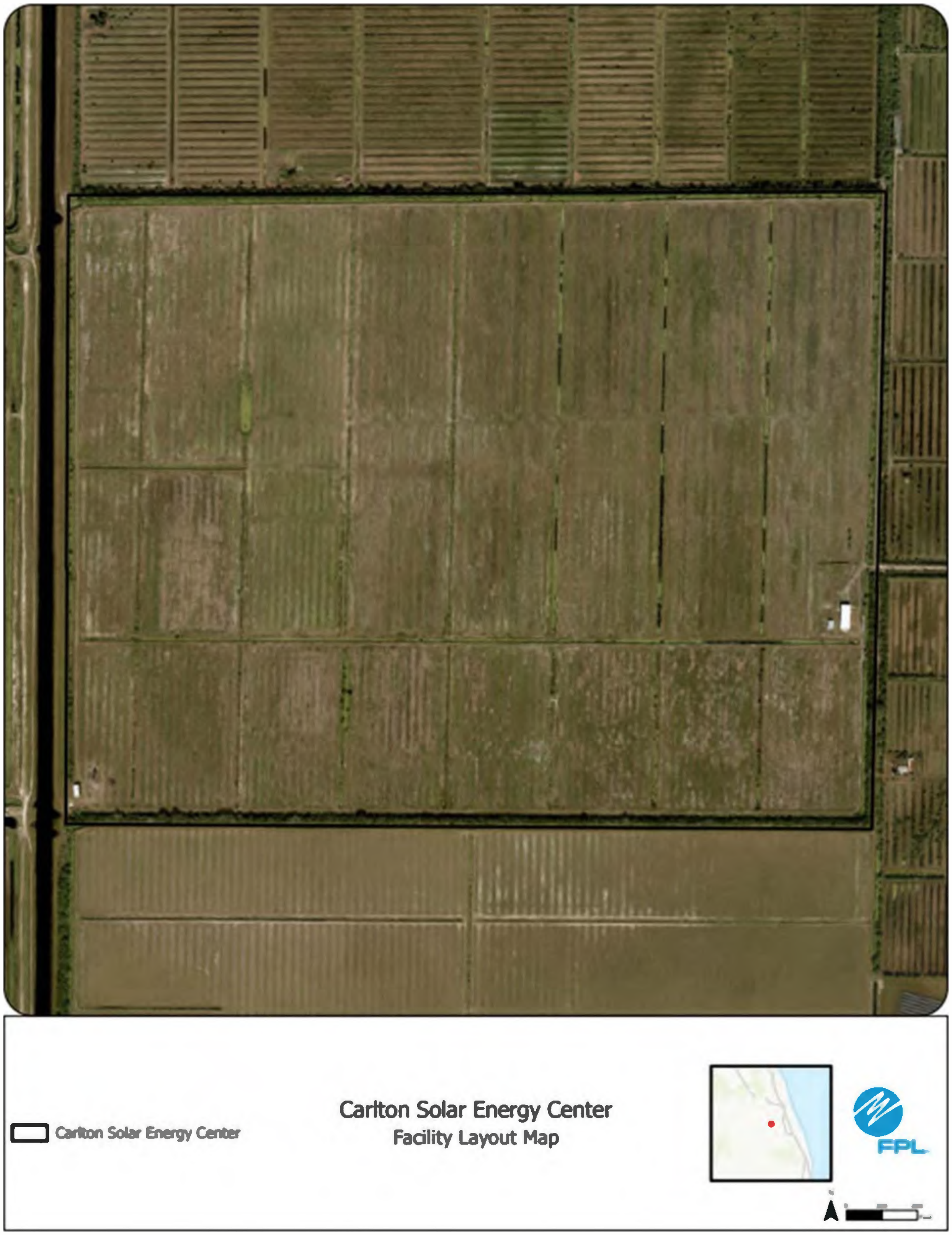
Carlton Solar Energy Center
Land Use/Land Cover Map
FPL


Carlton Solar Energy Center
Carlton Solar Energy Center
Facility Layout Map
FPL

FPL Area Potential Site #18: Owen Branch Solar Energy Center

This potential site in Manatee County is under evaluation for future PV.

a. U.S. Geological Survey (USGS) Map

See Figures on subsequent pages.

b. Existing Land Uses of Site and Adjacent Areas

Site was former citrus with open fields with an adjacent wetland system. Surrounding area is primarily agricultural land and low-density residential area.

c. Environmental Features

Maple Creek is in the vicinity of the site. Listed species expected in the vicinity of the site include Audubon's crested caracara, gopher tortoise and wading birds. No adverse impacts to listed species are anticipated.

d. Water Quantities Required

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable: Minimal.

Panel Cleaning: Minimal for PV and only needed in the absence of sufficient rainfall.

e. Supply Sources

Cooling: Not Applicable for PV.

Process: Not Applicable for PV.

Potable and Panel Cleaning: Onsite well or surface water or delivered to site.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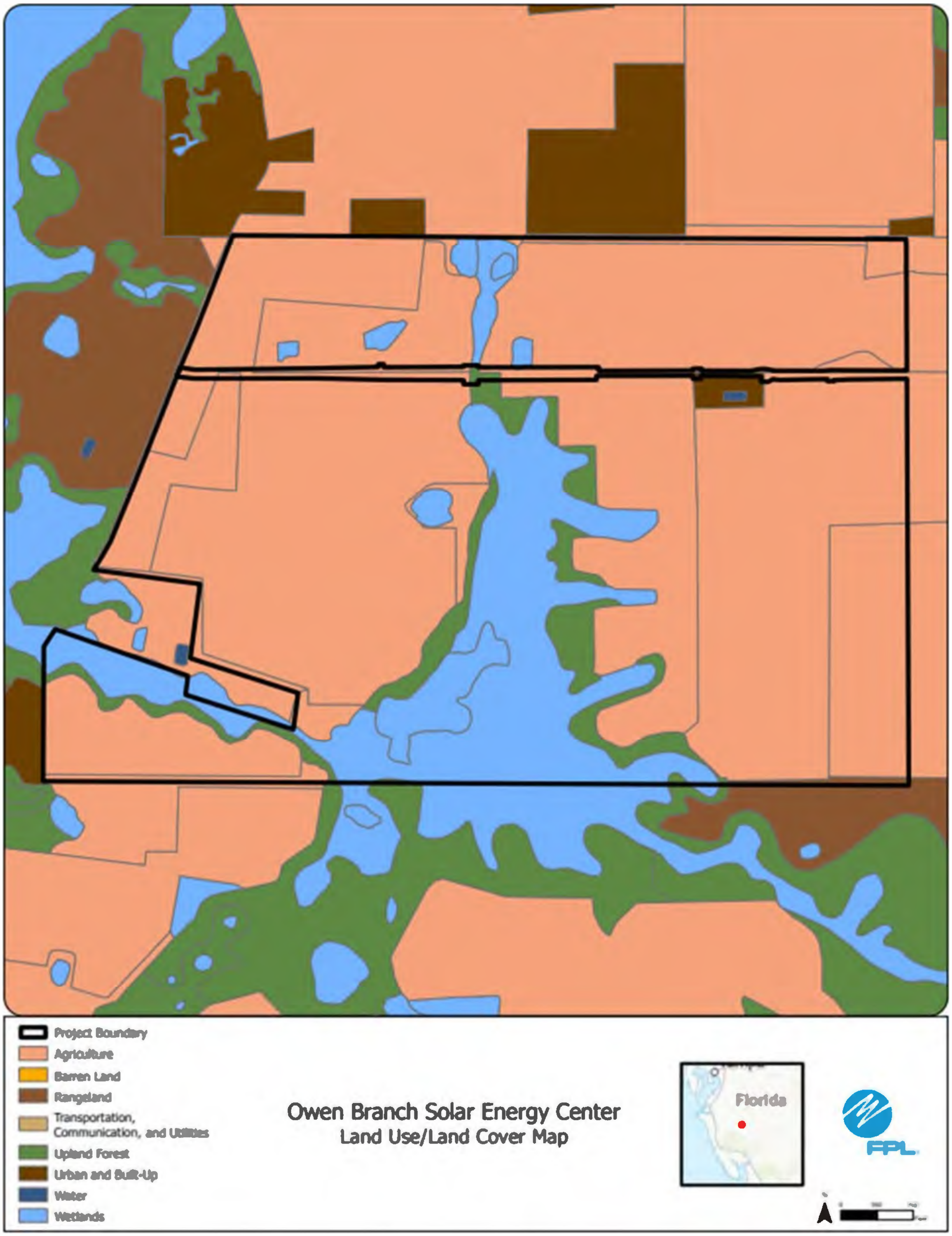
Owen Branch Solar Energy Center
Owen Branch Solar Energy Center
USGS Topography Map
Florida
FPL



Owen Branch Solar Energy Center
Land Use/Land Cover Map

Owen Branch Solar Energy Center

Owen Branch Solar Energy Center
Facility Layout Map

FPL

<u>EXHIBIT AWW-2</u>

DIRECT TESTIMONY AND EXHIBITS OF ANDREW WHITLEY IN FPL'S 2025 RATE CASE

[See Attached]

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250011-EI

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF ANDREW W. WHITLEY

Filed: February 28, 2025

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Andrew W. Whitley. My business address is 700 Universe Blvd., Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Engineering Manager in the Integrated Resource Planning ("IRP") department of FPL's Finance Business Unit.

Q. Please describe your duties and responsibilities in that position.

A. In my current position, I am responsible for the management and coordination of economic analyses that identify and evaluate resource alternatives to meet FPL's resource needs and maintain system reliability. The analyses I oversee are designed to determine the magnitude and timing of resource needs for FPL's system and are used to develop the Company's integrated resource plan.

Q. Please describe your educational background and professional experience.

A. I graduated from Lehigh University in 2004 with a Bachelor of Science in Mechanical Engineering. I joined FPL in 2004 as part of the Power Delivery team, undertaking various engineering duties related to initiating new service to FPL customers and maintaining the reliability of customers' existing services. In 2007, I joined the team now known as the IRP group. Since that time, I have been involved in and supported a variety of resource planning projects for FPL, including FPL's Ten Year Site Plans ("TYSP"), solar base rate adjustments, need determination proceedings for new power plants under the Florida Power Plant Siting Act (including the Okeechobee Clean

Energy Center in 2015 and the Dania Beach Clean Energy Center in 2018), base rate proceedings, and the Demand-Side Management ("DSM") Goals proceedings. I became the Manager of the IRP group in 2022 and have served as the project leader for FPL's TYSPs since 2022.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit AWW-1 Summary of FPL Resource Adequacy Study (Prepared by E3)
- Exhibit AWW-2 Load Forecasts Used in the Current Analyses
- Exhibit AWW-3 Fuel Cost Forecasts Used in the Current Analyses
- Exhibit AWW-4 CO_2 Compliance Cost Forecast Used in the Current Analyses
- Exhibit AWW-5 Economic Analysis Results for the Combined 2026 and 2027 Solar and Battery Additions
- Exhibit AWW-6 Economic Analysis Results for the Combined 2028 and 2029 Solar and Battery Additions
- Exhibit AWW-7 With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis
- Exhibit AWW-8 Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs.

Q. Are you sponsoring or co-sponsoring any Minimum Filing Requirements in this case?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the resource planning process undertaken by FPL to identify optimal resource additions for the 2026-2029 period. Specifically, I identify FPL's system needs and detail how the battery storage and photovoltaic ("PV") solar resource options identified through the Company's resource planning process most cost-effectively promote the dependability and reliability of FPL's system. My testimony also describes how recent and ongoing changes in FPL's generation resource portfolio support the transition of FPL's production cost of service methodology from a 12 coincident peak ("CP") and 1/13th methodology to a 12 CP and 25% methodology as detailed in the testimony of FPL witness DuBose. I also support the 3-gigawatt ("GW") maximum established under FPL's proposed Large Load Contract Service-1 ("LLCS-1") tariff, which is detailed in the testimony of FPL witness Cohen. Lastly, my testimony establishes the appropriate new monthly incentive payment levels for two of FPL's largest DSM programs: the Commercial/Industrial Demand Reduction ("CDR") and Commercial/Industrial Load Control ("CILC") programs.

Q. Please summarize your testimony.

FPL employs a comprehensive system planning analysis to identify reliable, timely, and cost-effective system additions that meet FPL's unique system needs and ensure sufficient capacity and energy are available to serve all FPL customers for every hour of the year. FPL undertook such an analysis in identifying utility-scale battery storage and PV solar additions that are proposed to enter service between 2026 and 2029.

As FPL's system continues to incorporate additional cost-effective solar generation, the Company is continuing to adapt its resource planning to ensure that customers' reliability needs are met through available, dispatchable resources that provide value to customers. Just as FPL's system has advanced and modernized over time, resource adequacy must also be modernized to consider conditions that affect the delivery of power in times of greatest need. To that end, FPL performed a comprehensive, stochastic loss of load probability ("LOLP") analysis to ensure that FPL's proposed system additions optimally address system needs for each hour of the year. The results of the stochastic LOLP analysis, which are detailed in my testimony, demonstrate that FPL has a need for resources to be added throughout years 2026 to 2029. Specifically, FPL must meet a 32,322 MW firm capacity need by 2027 in order to maintain its LOLP requirement in that year, and that reliability requirement increases to 34,102 MW in 2030, representing an increase of 1,780 MW over that timeframe.

The economic analyses presented through my testimony show that PV solar additions, combined with battery storage installations, most cost-effectively address the reliability needs identified through the stochastic analysis and generate significant customer savings. My testimony demonstrates that the deployment of 2,086 megawatts ("MW") of PV solar facilities in 2026 and 2027, along with 2,239 MW of battery storage installations over that same time period, is expected to create $1,942 million in cumulative present value revenue requirement ("CPVRR") savings for FPL's customers. The combination of solar and battery storage provides complementary benefits for FPL's system, incorporating FPL's most cost-effective generation resource and, concurrently, allowing for continued reliable operation of the electric system during times when solar facilities are not generating. Together, these resources are less costly than new natural gas fired generation and, unlike natural gas generation, can be added in the near term to address FPL's current reliability needs.

Not only are solar and battery storage optimal resources for the 2026 and 2027 timeframe, they continue to be the best resource options to address FPL's reliability needs in the latter years of FPL's four-year plan. FPL's proposed 3,278 MW of solar installations and 1,192 MW of battery installations in 2028 and 2029 are expected to create $2,213 million in CPVRR savings for customers, making them optimal resources as compared to other alternatives. These resources will continue the trend of providing fuel-free generation from solar combined with the flexibility and capacity from battery storage and will ensure FPL's bulk electric system is powered by reliable, cost-effective generation.

With the continued deployment of cost-effective solar, FPL's net system peak continues to push further into the evening hours. This means that FPL's incremental generation resource needs are moving to a time of the day when FPL's solar generation is producing less output. This transformation in our generation fleet supports the transition to a 12 CP and 25% methodology as described in the testimony of FPL witness DuBose, as this methodology best reflects the realities of FPL's system and its incremental generation needs during peak hours.

Just as FPL's grid and resource supply continue to evolve, so does the nature of the customers who are being added to the system, requiring the Company to refine certain features of service and cost assignment. One such feature is the LLCS-1 tariff described in the testimony of FPL witness Cohen. Participation in this tariff, which is tailored to large load customers entering FPL's service area, must be capped in order to ensure that FPL has the generation supply resources needed to safely, reliably, and adequately serve all of its customers. The limitation of 3 GW for this service during the term of our proposed four-year plan, which my testimony supports, is a reasonable limitation given the resources that FPL could potentially add in the near-term to meet the needs of new customers with large electric loads.

The nature of FPL's system also affects the operational value and cost-effectiveness of FPL's CDR and CILC programs. Currently, the incentive levels for these programs do not align with the operational value that they provide to FPL and its general body of customers. As such, FPL proposes to lower the monthly incentive payment for the CDR program from its current level of $8.76/kW to $6.22/kW. FPL's CILC rate will be adjusted accordingly, as addressed by FPL witness Cohen. The revised incentive levels will ensure that the programs are still attractive to participants and do not burden non-participants with higher program costs than are needed to sustain the program.

II. RESOURCE ADDITIONS

Q. What generation resource additions associated with FPL's rate request is your testimony supporting?

A. My testimony supports the prudence of FPL's addition of utility-scale battery storage and solar generation proposed for years 2026 and 2027, as well as FPL's need for further additions of these resources in years 2028 and 2029. These additions, which were specifically identified through FPL's resource planning process as optimal and needed resources, will allow FPL to meet its capacity and energy requirements with reliable generation sources and are forecasted to generate billions of dollars in total savings for FPL's customers compared to other alternatives.

A. *Resource Planning – Process Overview*

Q. How does FPL determine its future demand and energy needs and how best to meet those needs?

A. There are three main goals of FPL's resource planning process:

1. Identify the timing of FPL's resource needs. The timing of future resource needs is largely determined by reliability standards, including planning reserve margin, generation-only reserve margin, and LOLP.
2. Identify the magnitude of these resource needs, *i.e.*, how many MW of capacity are needed to satisfy all reliability criteria.
3. Identify the type of resources, either supply-side or demand-side, that can meet the capacity needs while adding other resources that improve system economics. On an economic basis, this selection is determined by the option

that is projected to result in the lowest electric rates for FPL's customers while satisfying FPL's reliability standards.

Q. Please provide an overview of FPL's resource planning process.

A. FPL's resource planning process can be summarized by the following four tasks:

- <u>Task 1:</u> Determine the magnitude and timing of FPL's new resource needs to maintain a reliable system.
- <u>Task 2:</u> Identify the resource options and resource plans that are available to meet the determined magnitude and timing of FPL's resource needs (*i.e.*, identify the available competing options and resource plans).
- <u>Task 3:</u> Evaluate the competing resource options and resource plans based on system economics and non-economic factors.
- <u>Task 4:</u> Select a resource plan to meet the identified need.

Q. What are the reliability standards the Company uses to design its resource portfolio and determine the need for additional resources?

A. FPL uses three specific reliability criteria in projecting its future resource needs. The first criterion is a minimum total planning reserve margin ("PRM") of 20% for both summer and winter peak hours. The minimum 20% total PRM criterion was approved by the Commission in Order No. PSC-99-2507-S-EU issued in Docket No. 981890-EU.

The second reliability criterion used by FPL is an LOLP criterion. LOLP is a projection of how well an electric utility system may be able to meet its firm demand (*i.e.*, a measure of how often firm load may exceed available resources). In contrast to a reserve margin approach that looks at the one summer peak hour and the one winter peak hour, the LOLP approach looks at the peak hourly demand for each day of the year. The LOLP approach takes into consideration the probability of individual generators being out-of-service due to scheduled maintenance or forced outages, the variability of load, the variability of production from intermittent generation resources, and the availability of duration-limited resources, such as battery storage and demand response programs. An LOLP analysis models each of these variables to generate a multitude of scenarios and the associated probability of a generation shortfall in these scenarios can be calculated. LOLP is typically expressed in terms of "numbers of times per year" that the system firm demand cannot be served. FPL's LOLP criterion is a maximum of 0.1 days per year, or one day in ten years. This LOLP criterion is commonly used throughout the electric utility industry and is consistent with North American Electric Reliability Corporation reliability planning standards.

The third reliability criterion used by FPL is a minimum generation-only reserve margin ("GRM") of 10%. The issue of having a sufficient generation component of the projected total reserve margin has been discussed annually in FPL's TYSP since 2011, and the GRM was adopted by FPL as a reliability criterion beginning in 2014. The GRM must be applied only after evaluating the amount of DSM in a resource plan.

Q. Has FPL expanded its reliability analysis to account for features that are specific to FPL's evolving system?

A. Yes. FPL's system has evolved over time such that the reliability analyses of the past do not sufficiently detect resource adequacy risks associated with FPL's generation profile. As I referenced earlier, FPL's incorporation of cost-effective solar has increased to the extent that the peak hour of the year – *i.e.*, the hour of greatest demand on the system – is no longer the most critical hour for determining reliability need. Now, the most critical time for capacity on FPL's system is at peak net demand, which occurs between 5:00 p.m. and 8:00 p.m., when solar facilities are providing less generation output. For these hours, as well as all other hours throughout the year, FPL needs additional, more modernized modeling analysis to determine its resource adequacy and identify where its greatest resource needs lie. Thus, for its 2025 resource planning, FPL added a stochastic LOLP analysis tailored to its system to identify (1) hourly periods of the year where there is increased likelihood for a loss of load, and (2) available resources that can remediate the potential for that loss.

Q. How does stochastic LOLP modeling work?

A. Stochastic LOLP modeling incorporates vast amounts of data to develop a granular view of a utility's system adequacy in hour-by-hour segments. This modeling incorporates significantly more data in assessing system reliability than a traditional LOLP analysis, providing a substantially wider range of load and generation conditions across numerous scenarios. Through this analysis, a utility can more effectively determine the sufficiency of its hourly generation supply throughout the year, which, in turn, allows it to identify any needed system additions.

Q. How does the stochastic LOLP analysis differ from the reliability analyses FPL has previously used to identify resource needs?

A. The stochastic LOLP analysis incorporates a tremendous volume of system-specific data to develop a probabilistic hourly load and supply projection and identify the system's reliability needs. A traditional PRM analysis, however, provides a simplified look at system operation, examining only the peak demand hour at two times of the year – once in the winter and once in the summer – without considering the unique generation attributes of the utility's fleet. The PRM analysis therefore leaves an analytical shortcoming, particularly for systems that incorporate substantial renewable generation. For example, as FPL's solar generation portfolio has increased, the hours of the day with the least reserves are more likely to be found in the evening as the sun begins to set and solar generation decreases, which a PRM analysis does not fully reflect. In addition, the traditional PRM analysis also fails to capture the interactive effects of non-dispatchable generation and load, which have become increasingly challenging to predict and model. The stochastic LOLP analysis, on the other hand, accounts for and models these factors, assessing resource availability at every hour of the year and identifying the periods when reserves are most depleted, wherever they may fall.

The stochastic modeling also presents a more sophisticated analysis than FPL's prior LOLP analyses. A traditional LOLP analysis models expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages. The stochastic LOLP analysis, however, simulates a random selection of plant outages, which better reflects the unpredictable nature of unavailable generation as observed in normal system operations. Additionally, a traditional LOLP analysis models an expected solar generation profile, whereas the stochastic LOLP analysis produces a reliability assessment that captures the natural variability in solar production due to weather conditions. The stochastic LOLP model also better captures the synergistic interactions between load and non-dispatchable generation because it models the variability of each input separately.

Q. Did FPL engage an outside consultant to assist in developing FPL's stochastic LOLP analysis?

A. Yes. To assist with determining the hourly reliability needs specific to its system, FPL engaged Energy and Environmental Economics, Inc. ("E3"), a consulting firm with experience advising state agencies, regulators, system operators and utilities on energy policies. E3 provided advanced stochastic LOLP modeling that accounted for variability in, among other things, generating resource availability, generating resource output, and system load. The modeling also included an hourly assessment of FPL's system reliability. The scope of E3's analysis assessed the marginal reliability benefits of resources with disparate generating characteristics, such as thermal generation, solar, battery storage, and demand response.

Q. How were the inputs to the stochastic LOLP model developed?

A. E3 coordinated with FPL and used hourly temperature data from representative weather stations to develop hourly load profiles using a machine learning algorithm trained on actual load and temperatures from 2003 to 2023. E3 also used historic satellite data to simulate hourly solar generation at each of its current and future solar generating sites for the 1980 to 2023 period, as well as actual historical generating unit availability data to calculate an expected forced outage rate and a mean time to repair for every generating unit in the FPL fleet. The model used these inputs to randomly select which units may experience an outage at any given time within the simulations.

Q. What were the results of the stochastic LOLP analysis and how did FPL incorporate these results into its 2025 resource planning?

A. The stochastic analysis revealed that LOLP vulnerabilities will arise if FPL's resource planning is not modified. As shown in Exhibit AWW-1, FPL needs 32,322 MW of firm capacity to be available in 2027 in order to maintain an LOLP of 0.1 days-per-year in that year – and the required reliability need to reach the same 0.1 threshold increases to 34,102 MW in 2030, representing an increase of 1,780 MW. The stochastic analysis shows that not adding sufficient generation resources during the 2026 through 2029 time period to address the identified needs would cause FPL's LOLP to not meet the 0.1 days-per-year threshold and could potentially result in scenarios where FPL is unable to provide its customers with electricity, a circumstance that FPL's resource planning must address and avoid.

To address the resource need demonstrated through the stochastic analysis, FPL's resource planning process identified resources to timely address the need, while maintaining all reliability criteria, and tested the cost-effectiveness of the available resource options.

Q. What forecasts and assumptions did FPL use in its 2025 resource planning process?

A. Every year, FPL updates its forecasts as part of its resource planning process and in support of filing its yearly TYSP, including considerations of supply-side efficiencies. In its 2025 resource planning work, which supports the resource additions identified in my testimony, FPL is using the following forecasts:

1. A forecast of projected hourly load, dated November 8, 2024, which is provided with my testimony as Exhibit AWW-2;
2. A forecast of fuel prices (natural gas, coal, and oil), dated September 3, 2024, which is provided with my testimony as Exhibit AWW-3; and
3. A forecast of carbon dioxide (“CO_2”) compliance costs, dated September 28, 2022, which is provided with my testimony as Exhibit AWW-4.

FPL’s 2025 resource planning also reflects unit retirements that affect the Company’s projected resource needs, including the retirement of Gulf Clean Energy Center Units 4 and 5 by the end of 2029.

Q. What is FPL’s process for selecting new resources to meet identified system needs?

FPL’s resource selection process is guided by the AURORA planning model and incorporates the stochastic LOLP modeling results I detailed earlier. The AURORA model utilizes sophisticated programming to conduct an extensive evaluation of potential resource plans that can meet the Company’s reliability requirements. FPL has presented the Commission with outputs from this model in numerous prior proceedings, and it is being used to develop FPL’s 2025 TYSP.

To develop a resource plan that is specific to FPL's needs, the AURORA model incorporates a number of forecasts and operating assumptions into its analysis including the following:

- The minimum 20% total Reserve Margin reliability criterion described earlier;
- Any additional resource needs from FPL's other reliability criteria;
- Forecasts for peak load, energy, fuel prices, and environmental compliance costs;
- Projections of future incremental DSM demand and energy additions, based on FPL's proposed DSM Plan, which will be filed by March 18, 2025;
- The existing capabilities of the units on FPL's systems, and any planned changes to those units; and
- Projections of fixed and variable costs, and the operating characteristics of a variety of generation options to meet FPL's resource needs in the future.

FPL ran the AURORA model with these assumptions to identify and test the cost-effectiveness of resource additions for inclusion in this proceeding as well as the 2025 TYSP.

I reviewed the underlying assumptions and modeling methodology, and they are reasonable and consistent with how FPL has conducted forecasts for prior investments that have been approved by the Commission.

Q. How does FPL forecast DSM and energy efficiency in its resource planning analysis?

A. FPL's resource planning assumes 100% achievement of its DSM and energy efficiency goals, which are approved by the Commission consistent with the Florida Energy Efficiency and Conservation Act ("FEECA"). Specifically, FPL accounts for the following projected DSM impacts as "line-item reductions" to the forecasts: (1) the impacts of incremental energy efficiency that have been implemented after the 2024 summer peaks have occurred, (2) projected impacts from incremental energy efficiency and load management, and (3) the impacts from previous signups in FPL's load management programs that will continue through 2034. Modeling DSM in this way reflects the full benefit associated with FPL's Commission-approved DSM programs.

Q. How have FPL's prior DSM efforts affected its system?

A. The Company's DSM efforts through the end of 2024 have resulted in a cumulative summer peak reduction of 5,695 MW at the generator and an estimated cumulative energy savings of 102,684 GWh at the generator. Without these reductions FPL would have required the equivalent of approximately 68 new 100 MW generating units to meet its peak load.

Q. How does FPL determine the cost-effectiveness of its potential resource options?

A. FPL assesses the CPVRR of potential resource options to make this determination. CPVRR is a metric focused on total system economics and rate impacts and allows for a comparative evaluation of the cost-effectiveness of various resource options. FPL assesses the CPVRR of competing resource alternatives by comparing the alternatives' abilities to economically meet an identical system load. This enables FPL to rank potential alternatives according to their respective impacts on both electricity rates and system revenue requirements. The CPVRR analysis therefore informs and furthers FPL's objective of minimizing the Company's projected levelized system average electric rate (*i.e.*, a Rate Impact Measure or "RIM" methodology), which is a tangible benefit to customers.

Q. How many potential resource plans did the AURORA model evaluate for FPL's system?

A. After incorporating FPL's input parameters, AURORA evaluated hundreds of possible resource plans that met FPL's future resource needs using only generation or supply options. These resource plans included consideration of all potentially implementable generation resources, including solar, battery storage, and fossil options. The model identified utility-scale battery storage and solar resources as optimal additions based on their CPVRR relative to other resources and their ability to address input parameters specified for the model run.

Q. How did FPL review the AURORA outputs in light of the stochastic LOLP analysis findings?

A. FPL tested the resource additions identified by AURORA to determine the most cost-effective resources that could address FPL's reliability needs as identified through the stochastic LOLP analysis. This testing procedure was a necessary and additive component of the resource planning process, as the AURORA model identifies resource options on the basis of the Company's minimum reserve margin requirement, which is only analyzed at the system's summer and winter peaks (*i.e.*, two peak hours per year).

Q. What resource additions did FPL identify that most cost-effectively address the reliability needs identified through the stochastic LOLP analysis?

A. FPL's resource planning identified the following installations as the most cost-effective to meet FPL's resource needs in the 2026 through 2029 timeframe:

- 1,419.5 MW of battery storage and 894 MW_{AC} of solar in 2026;
- 819.5 MW of battery storage and 1,192 MW_{AC} of solar in 2027;
- 596 MW of battery storage and 1,490 MW_{AC} of solar in 2028; and
- 596 MW of battery storage and 1,788 MW_{AC} of solar in 2029.

These proposed additions represent a greater than 50% reduction in planned solar for 2026 and 2027 as compared to FPL's 2024 TYSP, in favor of the reliable firm capacity provided by utility-scale battery storage, which more than doubles relative to the battery storage additions identified for 2026 and 2027 in FPL's 2024 TYSP. Years 2028 and 2029 represent similar decelerations of solar deployment in favor of additional MW of battery storage capacity as compared to the 2024 TYSP.

Q. Is it your assessment that these are the optimal system additions for FPL in years 2026 through 2029?

A. Yes. These are the most cost-effective system additions to meet FPL's reliability needs identified through the stochastic LOLP analysis and ensure sufficient capacity and generation production for every hour of the year. Consistent with my CPVRR analyses, which are described in my testimony below, these system additions meet FPL's resource needs and are also projected to save customers several billions of dollars over the life of the assets.

Q. Could purchasing power as needed be a reliable solution to address the resource needs identified by FPL's LOLP modeling?

A. No. Having consulted with FPL's Energy Marketing and Trading business unit, purchasing power to address these needs would not be a viable solution. Purchasing power, either in the near- or long-term, would require that capacity be consistently available at the times FPL most requires it. However, the availability of power purchases would be extremely limited during any situation with higher-than-normal loads in Florida. Additionally, long-term power supply agreements often require power deliveries to be scheduled a day ahead or contain other scheduling limitations that would compromise FPL's ability to flexibly meet hour-to-hour supply needs. Further, the supply of wholesale power available in the Florida market is limited and may become increasingly more so as utilities in the Southeast continue to anticipate (and potentially recognize) significant load growth. Therefore, to rely on as-needed purchases during times of system constraint would jeopardize FPL's power supply availability, a circumstance that FPL must plan to avoid.

Q. Is it your assessment that the battery storage and solar additions you identified are prudent compared to adding natural gas-fired generation?

A. Yes. The addition of solar generation and battery storage is more cost-effective than constructing new natural gas generation. As demonstrated in my CPVRR analyses presented below, using natural gas-fired generation to address FPL's reliability needs would increase costs for FPL customers by billions of dollars compared to the utility-scale battery storage and solar resources I identified.

Q. Aside from being more costly, are there other reasons why adding natural gas-fired generation is not a suitable substitute for the solar and battery storage additions you identified?

A. Yes. The potential to construct and bring natural gas generation to operation in the near term is severely limited. Combustion turbines ("CTs") cannot be quickly implemented and require multiple years to construct and reach operation. Moreover, gas supply available to FPL is limited, and the additional infrastructure required to increase the availability of gas supply takes time and cost to develop. This makes CTs unsuitable for addressing reliability needs in the near term.

Additionally, the components needed to construct new CTs have become increasingly difficult to timely obtain. Overseas demand and recent supply-chain issues have pushed the earliest realistic in-service date for CTs to late 2029 or early 2030. These in-service dates would lead to CTs being unable to meet FPL's resource needs in the 2026-2029 timeframe.

B. *FPL's Planned Resource Additions (2026)*

Q. Please provide an overview of FPL's current battery storage and solar portfolio.

A. At this time, FPL has 469 MW of utility-scale, grid connected battery storage installed on its system at three separate locations and is currently constructing 522 MW of new battery storage adjacent to seven existing solar energy centers. As for FPL's solar fleet, FPL had a total of approximately 7,038 MW_{AC} (nameplate) of utility-owned solar generation as of the end of 2024, all of which are PV facilities. FPL also has 894

MW_{AC} of solar generation in various stages of development that are expected to enter service in 2025, including those that are a part of the solar base rate adjustments approved in FPL's last base rate proceeding. These solar projects are spread throughout FPL's system, providing energy derived from cost-effective renewable solar resources throughout FPL's service area.

Q. How has the addition of the solar facilities you mentioned contributed to FPL's system?

A. Solar contributes to FPL's system, and has benefitted FPL's customers, in the following ways:

1. Solar provides a portion of its nameplate capacity as firm capacity during the times of FPL's system peaks.
2. Solar provides fuel-free (and emission-free) energy that reduces the fuel portion of customer bills. From 2021 through 2024, FPL customers have saved approximately $942 million in avoided fuel expenses from solar installed on FPL's system.
3. Since 2023, solar production from new sites has also been eligible for a Production Tax Credit that reduces the cost of solar and is passed on directly to FPL's customers.

All three of these factors have led to solar being an economic resource option for FPL and continue to drive the cost-effectiveness of solar in FPL's resource plans.

Q. What is FPL's resource need for 2026?

A. As identified in the stochastic LOLP analysis, FPL needs 1,663 MW of additional firm capacity to meet its LOLP requirement in 2027. To meet this need FPL must add firm capacity in 2026 so that it is positioned to meet the identified 2027 reliability need.

Q. What resources does FPL plan to add in 2026 to address this need?

A. FPL is proposing to add 1,419.5 MW of battery storage and 12 74.5 MW solar sites (894 MW) in 2026. Installation of these system additions is supported by FPL's resource planning analysis, undertaken in accordance with the process I described earlier. FPL witness Oliver provides additional details concerning each of these proposed solar additions, as well as those in 2027.

Q. How do these additions address the need identified in the stochastic LOLP analysis?

A. In short, the MWs provided by the 2026 additions allow FPL to address the reliability need identified through the stochastic LOLP analysis by 2027, while also maintaining FPL's adherence to all other reliability criteria. Adding these resources, along with additional resources in the first half of 2027, will bring FPL's projected LOLP under the 0.1 days-per-year standard for 2027.

The 2026 additions also provide two specific system needs identified through the stochastic LOLP analysis: (1) the additional need for stable, dispatchable capacity; and (2) the need for FPL to maintain sufficient generation to meet FPL's increasingly higher load. The proposed battery storage additions will have the ability to quickly discharge energy to FPL's system to address hourly operational requirements, which enhances the reliability of FPL's system. The facilities will also provide year-round capacity to promote system reliability regardless of the time of day or the weather conditions and enable low-cost energy to be stored and delivered when needed. In that way, the storage additions will serve as key resources that allow FPL to increase system reliability and flexibility by cost-effectively addressing times of peak energy consumption, which ordinarily occur in the evenings.

The solar additions, combined with the battery storage, allow FPL to maintain sufficient generation resources to reliably meet the needs of an increasing customer base and higher loads. In addition to FPL's peak demand growing, FPL's net energy load (*i.e.*, the amount of energy on the system throughout the year) is also growing. FPL's proposed solar additions help meet this increased energy need with energy that is produced cost-effectively and uses no fuel, thereby putting downward pressure on customer rates over the long-term.

The 2026 additions can also be sited, constructed, and operational within a much shorter timeframe than other generation resources, such as CTs as I discussed above.

Q. Are there additional considerations that support the inclusion of 1,419.5 MW of battery storage in 2026?

A. Yes. The continued deployment of low-cost solar generation, which generates electricity during daytime hours, is complemented by storage in order to continue to push low-cost power to the grid when needed. With FPL's typical net system peak (after accounting for solar generation) occurring in the evening time, storage capacity enables FPL to dispatch lower-cost electricity during these net peak times.

Also, FPL's combined-cycle fleet most often undergoes maintenance during the shoulder months, which have been susceptible to high load conditions. The stable capacity provided by battery storage helps to address higher loads and unexpected events, which in turn promotes system reliability.

Battery storage also provides variable cost savings via energy arbitrage – *i.e.*, charging when energy is the cheapest and discharging to avoid more expensive generation. Energy arbitrage becomes even more pronounced when a system has large amounts of solar, as is the case with FPL. Solar drives down the price of energy during the day, and batteries can discharge in the early evening to avoid more expensive generation starting or ramping up, increasing generation resource cost-effectiveness to the benefit of customers.

Q. Is the addition of the 2026 battery storage and solar facilities cost-effective?

A. Yes, as detailed in my CPVRR analysis below and attached to my testimony in Exhibit AWW-5, these additions, along with the proposed 2027 additions, are projected to save customers nearly $2 billion over the lives of the assets.

C. *FPL's Planned Resource Additions (2027)*

Q. What is FPL's resource need for 2027?

A. As identified in the stochastic LOLP analysis, FPL's total firm MW requirement increases by 626 MW from 2027 to 2028, and it must make additions in the beginning half of 2027 to address the identified 273 MW need for 2027 shown in Exhibit AWW-1.

Q. Please detail FPL's proposed resource additions in 2027 to address this need.

A. FPL's analysis supports the construction of 16 74.5 MW solar sites (1,192 MW) and another 819.5 MW of battery storage throughout 2027. Adding these resources (along with the 2026 additions) will allow FPL to meet its 0.1 days per year LOLP criterion throughout 2027.

Q. How do the 2027 additions address the need identified in the stochastic LOLP analysis?

A. These additions address the resource need identified for 2027 in the same manner I described for the 2026 additions above; that is, by providing the stable, dispatchable capacity and energy needed generation to meet FPL's identified system need. FPL's addition of 1,192 MW of new solar generation and 819.5 MW of battery storage in 2027 allow FPL to maintain a 0.1 days-per-year LOLP throughout 2027. Additionally, even with the 2027 additions, FPL must add additional firm capacity in the first half of 2028 to address a 19 MW shortfall identified for 2028.

Q. Are FPL's 2026 and 2027 resource additions supported by a CPVRR analysis?

A. Yes. FPL tested the cost-effectiveness of its 2026 and 2027 solar and battery storage additions to ensure they are the most cost-effective options to address the Company's identified reliability needs.

Q. What was the result of that CPVRR analysis?

A. The combination of FPL's planned 2026 and 2027 solar and battery storage additions result in $1,942 million CPVRR savings for FPL's customers, as compared to an alternative plan that excludes the additions. This analysis demonstrates that the facilities provide substantial savings for FPL's customers while addressing FPL's identified reliability needs. Exhibit AWW-5 provides the results of the CPVRR analysis.

D. *FPL's 2028 and 2029 Resource Needs*

Q. What is FPL's resource need for 2028 and 2029?

A. As identified in the stochastic LOLP analysis, FPL's need for additional firm capacity continues to increase in years 2028 through 2030. Between 2028 and 2029 FPL's total reliability need increases from 32,948 MW to 33,544 MW, an increase of 596 MW. Between 2029 and 2030, FPL's total reliability need increases from 33,544 MW to 34,102 MW, an increase of 558 MW. The stochastic LOLP analysis shows that without added resources in 2028 and 2029 to address this increasing growth, FPL will fall short of its 0.1 days-per-year LOLP standard.

Q. Has FPL identified which resources best address these needs?

A. Yes. Based on FPL's analysis the most cost-effective resources to meet those needs are 1,490 MW of solar in 2028 and 1,788 MW of solar in 2029, as well as 596 MW of battery storage in each of those years. These additions will allow FPL to maintain its 0.1 LOLP standard in both 2028 and 2029. As with 2027, FPL must add resources earlier in 2028 and 2029 to address MW shortfalls in those years of 19 MW and 104 MW, respectively. Additionally, as shown in Exhibit AWW-1, even with the proposed 2028 and 2029 additions, FPL will still have a reliability need in 2030 and beyond, which will have to be addressed in order to maintain an LOLP of 0.1 days-per-year.

Q. What is driving FPL's projected system needs in 2028 and 2029, and how do the identified resources meet those needs?

A. FPL's system is projected to continue growing throughout the 2028-2029 time period, such that energy from new cost-effective solar will be needed while capacity from battery storage will ensure that power can be reliably delivered to customers every hour of the year. As FPL's system continues to grow and leverage cost-effective solar generation, the requirement to maintain sufficient and readily dispatchable generation becomes increasingly necessary, as shown in the stochastic LOLP analysis.

As with FPL's 2026 and 2027 additions, the resources identified for 2028 and 2029 are projected to address the capacity need identified in the stochastic LOLP analysis and ensure that FPL's other reliability criteria are met. Additionally, these resources can be constructed and operational in time to meet the identified needs.

Q. Are the Company's identified resource additions in 2028 and 2029 forecasted to be cost-effective?

A. Yes. Not only do the 2028 and 2029 additions contribute to FPL's ability to provide reliable power to customers over every hour of the year, they are also cost-effective compared to adding gas-fired CTs.

Q. What are the projected CPVRR savings of a resource plan with the 2028 and 2029 additions as compared to a resource plan without these additions?

A. As demonstrated in Exhibit AWW-6, the projected CPVRR benefit to FPL's customers of adding the 2028 and 2029 additions compared to a plan that only adds CTs to address peak reserve margin needs is $2,213 million.

Q. Is FPL requesting approval for cost recovery associated with the 2028 and 2029 additions you have identified?

No, not in this proceeding. My testimony provides FPL's projected needs based on FPL's current resource planning. As discussed by FPL witnesses Bores, Laney, and Oliver, FPL's four-year plan proposes a Solar and Battery Base Rate Adjustment mechanism pursuant to which FPL would seek recovery for solar and battery storage facilities installed in 2028 and 2029 upon a showing of a resource or economic need based on updated information.

III. UPDATE TO COST OF SERVICE METHODOLOGY

Q. What production cost-of-service methodology is FPL proposing to use in this proceeding?

A. As detailed in the testimony of FPL witness DuBose, FPL is proposing to use a 12 CP and 25% allocation method for production plant to better align cost allocations among customer classes with changes to FPL's portfolio of generation resources.

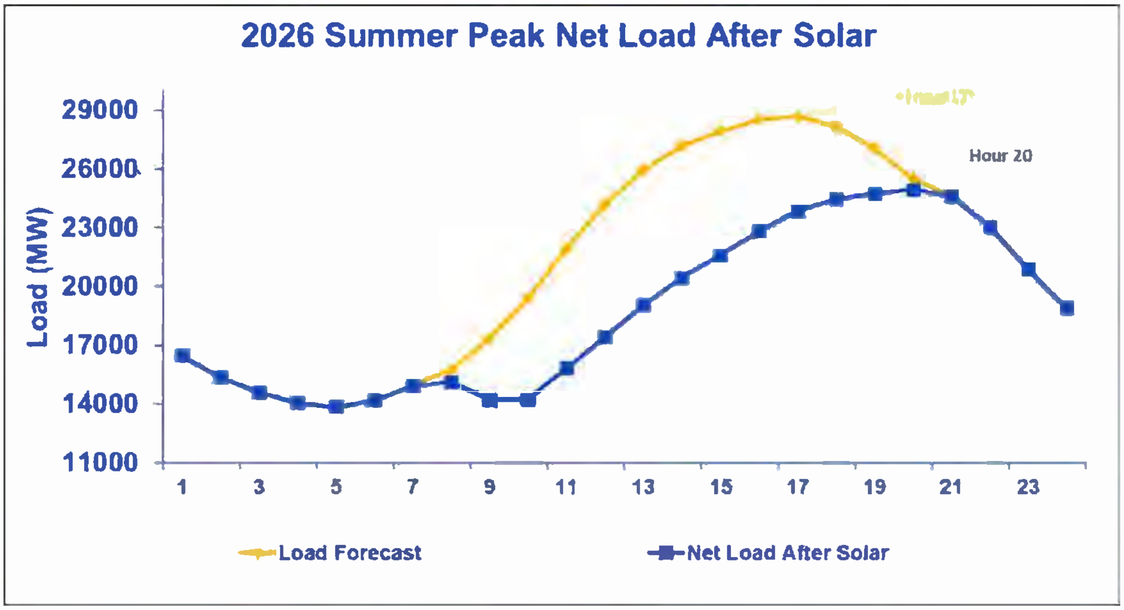
Q. What are the changes to FPL's generation portfolio that support the revised cost of service methodology?

A. As I detailed earlier in my testimony, FPL has installed a significant amount of cost-effective solar generation and plans to continue expanding its development of solar resources. This expansion is pushing FPL's critical time of peak to later in the evening, which is when incremental dispatchable generation is needed.

With FPL's implementation of more solar generation, FPL has begun using a "net peak load" methodology to assign firm capacity values to solar added to its system. This methodology takes the hourly shape of FPL's load forecast, then subtracts the projected hourly solar generation from the load. The resulting shape shows FPL's "net peak load" and represents the load that incremental generation additions must meet. As discussed previously, as more solar generation is added to FPL's system, the time of the net peak shifts further into the evening – therefore, incremental solar additions have an incrementally lower firm capacity value as their generation declines in the peak evening hours. Despite this decline in firm capacity value for solar, solar generation continues to be the most cost-effective resource for FPL's system, based on the energy needs that it serves throughout the day.

As shown in Figure 1 below, FPL's system peak in 2026, excluding solar generation, occurs at hour-ending 5:00 p.m. in the summer. However, after accounting for the projected output from FPL's incremental solar additions through 2026, FPL's net load peak shifts to hour-ending 8:00 p.m.

FIGURE 1



These changes in FPL's system move the effective system peak later into the evening, and the types of customers and customer activities that cause the need for incremental generation during these times are different. These changing system dynamics and the changing times of FPL's net load peak support the Company's change in production cost-of-service methodology, as detailed by FPL witness DuBose.

IV. LARGE LOAD CONTRACT SERVICE

Q. What tariff changes is FPL proposing to address the impacts of future large load customers?

A. As explained in the testimony of FPL witness Cohen, FPL is proposing new rate schedules for future customers with a projected new or incremental load of 25 MW or more and a projected load factor of 85% or more. Those rate schedules, LLCS-1 and Large Load Contract Service-2 ("LLCS-2"), are designed to proactively address the potential scenario that future customers of this size request service within the FPL service area and, if so, to ensure that the general body of customers is protected from the higher costs to serve such large load customers. In order to serve a customer of this magnitude, FPL would need to make significant investments in new incremental generation capacity that, but for the customer's request for service, would not otherwise be incurred or needed to serve the general body of customers.

Q. Why is the maximum of 3 GW of demand appropriate for LLCS-1?

A. As explained by FPL witness Cohen, rate schedule LLCS-1 will be available to serve a combined total of 3 GW of demand in three specific regions of the Company's service area. These regions were selected based on their proximity to FPL's transmission facilities and areas suitable for the incremental generation capacity necessary to serve up to a combined total load of 3 GW. In these regions FPL would be able to accommodate up to approximately 1 GW of new demand without significant network upgrades – thereby minimizing overall costs incurred – while still meeting all of FPL's reliability criteria. Additionally, the 3 GW maximum for rate schedule LLCS-1 is appropriate because it corresponds to the amount of generation that FPL forecasts it can reasonably and safely ramp up and deploy on its system starting in 2028 to serve up to 1 GW of new demand in each of the selected regions. The 3 GW maximum demand for schedule LLCS-1 therefore mitigates the potential for reliability issues and costly new system investment, and better ensures that FPL can safely dispatch system resources efficiently to meet the high load factor demand of these potential new large load customers.

V. INCENTIVE PAYMENT LEVELS FOR CDR & CILC

Q. Please describe the CDR and CILC programs.

A. The CDR and CILC programs are FPL's largest DSM programs for commercial and industrial customers. Voluntary participants in these programs agree to allow FPL to remotely lower a portion of the participant's served electric load as needed (for example, during a period of high electrical demand on FPL's system) in exchange for the participant receiving a reduction in their monthly bill.

The two programs have a combined demand reduction capability of slightly more than 900 MW[1]. The CDR program is open to new participants. The CILC program was officially closed to new participants in the year 2000 and was essentially replaced by the CDR program, which offers a similar load management program to commercial and industrial customers.

[1] This value is the maximum summer peak value, calculated at the generator.

Q. What are the current incentive payment levels for the two programs?

A. The incentive payments are administered differently for each program. For the CDR program, the incentive is administered as a $/kW credit on the monthly bill. The current CDR program monthly incentive is $8.76/kW. For the CILC program, the incentive is administered as a percentage reduction of the base bill as discussed in the testimony of FPL witness Cohen.

Q. How were the current incentive payment levels of the two programs set?

A. The current incentive payment levels were set pursuant to FPL's 2021 base rate settlement agreement approved by Order No. PSC-2021-0446-S-EI. Paragraph 4(e) of that agreement set incentive payments for the CDR and CILC programs at the then-current level until, at least, "the effective date of new FPL base rates implemented pursuant to a general base rate proceeding." The Commission affirmed that a general base rate proceeding is the appropriate proceeding for setting incentive payments for these programs for FPL with the Commission's approval of stipulations in Order No. PSC-2024-0505-FOF-EG.

Q. How does the current CDR rate compare with the rate that was in effect when most participants joined the program?

A. Approximately 75% of the existing CDR participants joined the program during 2000 to 2012. During this time period, the monthly incentive was initially $4.75/kW then decreased to $4.68/kW, representing just over 50% of its current amount.

Q. Is FPL proposing to change the monthly incentive payments for both programs in this proceeding?

A. Yes. FPL is proposing to change the incentives to align them with the value they provide to customers. My testimony discusses the proposed changes in incentive payments in terms of a $/kW payment format. The CILC program's incentive payment is a percentage reduction of the base bill. FPL witness Cohen discusses how rates are designed for CILC customers, and those rates are shown in Exhibit TCC-6.

Q. How large a factor are the incentive payments in relation to the overall costs of the programs?

A. The programs have three cost components: (i) administrative costs, (ii) unrecovered revenue requirements, and (iii) monthly incentive payments. Using the CDR program as an example, the monthly incentive payments account for approximately 99% of the projected total CPVRR cost of the CDR program. Consequently, the monthly incentive payment is the primary "driver" of program costs.

Q. How does FPL evaluate the economic value of the CDR and CILC programs?

A. FPL analyzes the cost-effectiveness of each of its DSM programs, including the CDR and CILC programs, using three cost-effectiveness screening tests: (i) the RIM test, (ii) the Total Resource Cost ("TRC") test, and (iii) the Participant test.

For programs such as CDR, the RIM test is the cost-effectiveness test used to set an appropriate incentive level. The TRC test does not incorporate incentives into its calculation of costs, and therefore does not change as the value of incentive payments change. The Participant test measures the benefit to the participant against any incremental costs the participant in a program incurs. For CDR, the participant does not incur any direct incremental costs to participate, resulting in an infinite cost-benefit ratio. For these reasons, FPL relies on the RIM test to analyze the appropriate incentive level for CDR in terms of economic value.

Q. How does FPL determine the full value of the CDR and CILC programs?

A. To make this determination, FPL evaluates the economics of two comparative resource plans developed using the AURORA optimization model. One resource plan, the "With Programs" plan, assumes the inclusion of all of the approximately 900 MW of demand reduction capability from existing CDR and CILC participants and the approximately 6 MW per year of projected new CDR participants. However, for purposes of the analysis, the projected monthly incentive payments for both existing and new participants are zeroed out. As a result, the "With Programs" resource plan accounts for all of the demand reduction benefits of the CDR and CILC programs but assumes no incentive payment costs.

The second resource plan, the "Without Programs" plan, assumes that all the existing CDR and CILC MW, all projected new CDR sign-ups, and all incentive payments for both programs are removed from the resource plan starting in January 2026.[2] The AURORA model then selected the most cost-effective generation resources to replace the loss of 900+ MW of demand reduction capability.

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[2] Note that the use of the January 2026 "exit" date assumption means all existing participants in the CDR and CILC programs would exit the programs with less than one year's notice (which ignores the 5-year exit notice terms for both programs). Because of this assumed sudden loss of 900+ MW of demand reduction capability, replacement capacity needs to be added relatively quickly. As a result, the January 2026 exit assumption maximizes the projected value of the two programs for purposes of this analysis.

The projected CPVRR costs of the two resource plans were then compared. The projected CPVRR cost of the Without Programs resource plan, \$100,390 million, is higher than the projected CPVRR cost of the With Programs resource plan, \$99,322 million, because the Without Programs resource plan must add new resources to make up for the loss of the 900+ MW of demand reduction capability offered by the CDR and CILC programs. The two resource plans, and the projected CPVRR costs for each plan, are presented in Exhibit AWW-7.

The \$1,069 million (\$100,390 - \$99,322 = \$1,069) CPVRR differential represents the projected benefits of the CDR and CILC programs through 2071. It also represents – after accounting for the administrative costs of the CDR and CILC programs – the amount of CPVRR cost that can be paid in the form of monthly incentive payments to CDR and CILC participants in the With Programs resource plan before both resource plans will have an identical CPVRR cost (assuming that there will be no future changes to the current projections of CDR and CILC benefits or program administrative costs).

Q. What other considerations were taken into account when developing the proposed new monthly incentive payment for the two programs?

A. Three other considerations were taken into account in establishing the proposed incentive payment levels for the programs. The first consideration for any DSM program, including these two programs, is that the maximum incentive level that should be considered is one that results in program costs exactly equaling program benefits (*i.e.*, a RIM benefit-to-cost ratio of 1.00). Such a result means that program participants will benefit from the program and that the utility's general body of customers should be indifferent regarding whether the program is offered because electric rates are unchanged compared to what they would be if the DSM program had not been offered and the best generation alternative had been chosen instead.

The second consideration is that, all else equal, it is preferable for a DSM program's RIM benefit-to-cost ratio to be greater than 1.00. In such a case, all customers benefit from the DSM program, not just the program participants. This consideration recognizes that paying the maximum incentive for a DSM program does not maximize the benefit to the general body of customers – it merely ensures that the general body is indifferent.

The third consideration is how the demand response is credited in terms of capacity in FPL's system. Based on the stochastic LOLP analysis, demand response is limited to a certain percentage of its capacity, which, over time, degrades its potential to serve FPL's increasing load. Therefore, the further beyond 1.00 the RIM ratio is, the more assurance there is that the credit given to CDR customers does not outweigh its benefits to the general body of customers.

Q. Taking these considerations into account, how did FPL determine the appropriate incentive level for these programs?

A. First, cost-effectiveness calculations were performed for the current CDR monthly incentive level of \$8.76/kW (Scenario 1). These calculations are presented in Exhibit AWW-8. The left-hand side of Exhibit AWW-8 presents seven assumptions used in the calculations. Assumption (1) is the CPVRR difference between the With Programs resource plan and the Without Programs resource plan that appears in Exhibit AWW-7, which is $1,069 million. Assumption (2) is the projected CPVRR administrative cost of the combined CDR and CILC programs, which equates to $10 million. Assumption (3) is the current monthly incentive level for CDR of $8.76/kW. Assumptions (4) through (7) present other inputs used in calculations.

The right-hand side of Exhibit AWW-8 presents a table that shows the results of calculations for two scenarios. In Scenario 1, the projected RIM benefit-to-cost ratio for the 900+ MW of CDR and CILC with the current monthly incentive level of $8.76/kW is shown: 1.06. This result shows that the program and its current incentive level is beneficial for participants but, with a RIM ratio of near 1.00, leaves the general body near the point at which they are indifferent to the program.

For that reason, and based on the three evaluative considerations discussed above, FPL determined that it was appropriate to lower the monthly CDR incentive level to $6.22/kW. Scenario 2 in Exhibit AWW-8 shows the same calculations for the programs with the revised monthly incentive level, as well as the resulting RIM benefit-to-cost ratio of 1.49. This higher benefit-to-cost ratio provides a reasonable level of assurance that the programs will remain cost-effective for all customers for the expected 4-to-5-year period until the incentive levels are next reviewed. This value also ensures that CDR is still beneficial to participants and does not burden non-participants with higher program costs than are required for maintenance of the program. Moreover, as stated in the testimony of FPL witness Cohen, the annual savings associated with the reduction in the credit for CILC and CDR customers is approximately $22 million in 2026 and 2027.

Q. How does the proposed monthly incentive level compare to the incentive level that existed at the time most of the CDR participants joined the program?

A. As I referenced above, approximately 75% of the existing CDR participants joined the program during 2000 to 2012, when the monthly incentive was initially $4.75/kW then decreased to $4.68/kW. The proposed new CDR monthly incentive level of $6.22/kW is nearly 31% higher than the incentive level that was in place when the majority of CDR participants joined the program.

Therefore, this proposed new incentive level will be sufficient to help ensure the cost-effectiveness of the CDR and CILC programs for a 4- to 5-year period, achieve future CDR program participation needed to meet FPL's approved DSM Goals, retain existing CDR and CILC participants, and ensure that non-participants are not bearing unnecessary program costs.

Q. Does this conclude your direct testimony?

A. Yes.

Florida Power & Light Resource Adequacy Study

February 21, 2025

Energy+Environmental Economics

Docket No. 20250011-EI
Summary of FPL Resource Adequacy Study (Prepared by E3)
Exhibit AWW-1, Page 1 of 30

Overview

- **FPL asked E3 to perform a loss-of-load study of the FPL system using E3's Renewable Energy Capacity Planning (RECAP) model to answer three key questions:**
  1. What is the FPL system's achieved reliability during 2027-2030 and 2035?
  2. What is the contribution of each resource type to maintaining resource adequacy?
  3. What is the nature, timing and duration of simulated loss-of-load events on the FPL system?
- **This report summarizes the results of that study**

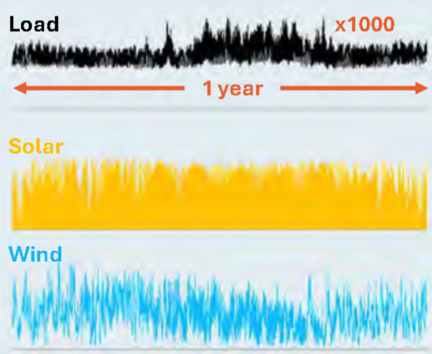
RECAP Model Overview

Energy+Environmental Economics

Overview of best practices in resource adequacy analysis

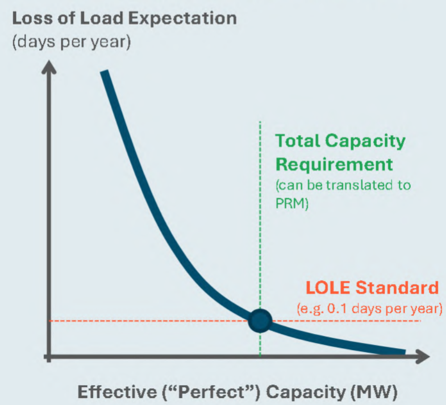
Step 1: Develop a representation of the loads and resources of an electric system in a loss of load probability (LOLP) model

LOLP modeling allows a utility to evaluate resource adequacy across all hours of the year under a broad range of weather conditions, producing statistical measures of the risk of loss of load



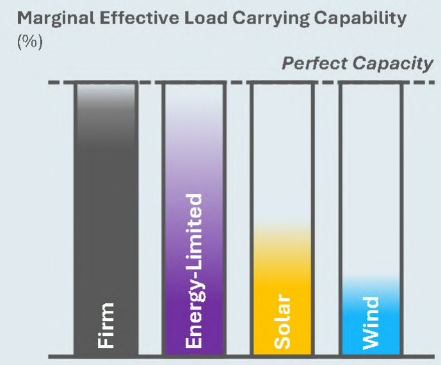
Step 2: Identify the amount of perfect capacity needed to achieve the desired level of reliability

Factors that impact the amount of perfect capacity needed include load & weather variability, operating reserve needs



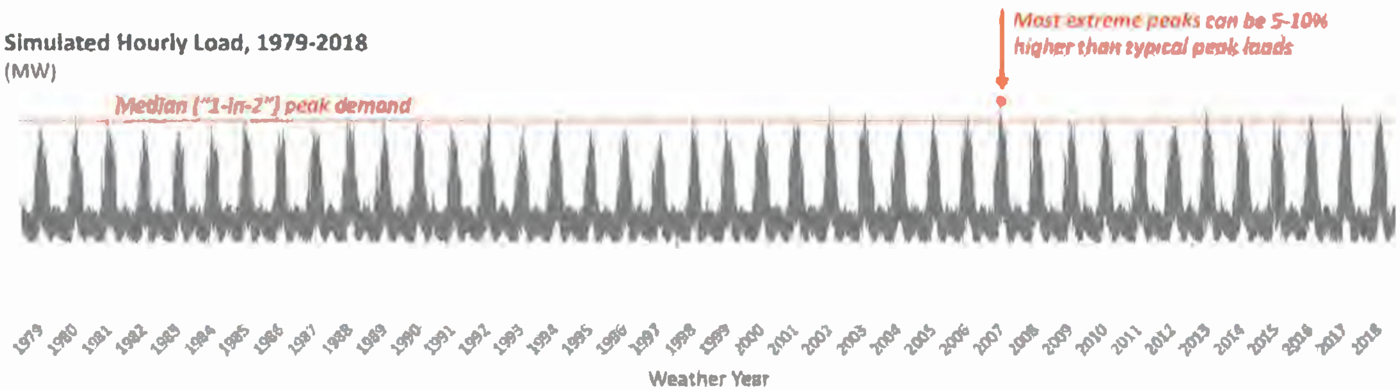
Step 3: Calculate capacity contributions of different resources using effective load carrying capability (ELCC)

ELCC measures a resource's contribution to the system's needs relative to perfect capacity, accounting for its limitations and constraints



Loss-of-load probability (LOLP) modeling is the foundation for understanding resource adequacy needs

- LOLP modeling can be thought of as an organized way to analyze the potential for extreme weather and other events to cause a supply shortfall
- LOLP captures factors that matter for reliability such as:
  - High loads due to extreme weather
  - Correlations between load and renewable conditions
  - Energy and capacity limitations
  - Dispatch behavior of energy-limited resources such as energy storage and demand response



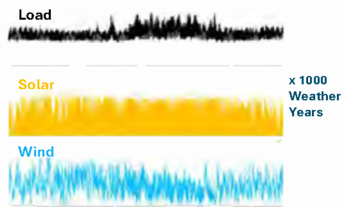
RECAP – Loss-of-Load-Probability Model

A loss-of-load-probability model is designed to study the reliability dynamics of an electric system

+ **LOLP model simulates the operations of the electricity system under hundreds of scenarios to capture different conditions, including:**
  - load variability,
  - weather variability,
  - renewable output variable, and
  - forced outage events
+ **Key LOLP Modeling outputs:**
  - System reliability
  - Target Planning Reserve Margin
  - Capacity Shortfall
  - Capacity Value of Resources

Temperature and Load Artificial Neural Network Simulation

Capturing hourly load conditions under mild and extreme historical weather

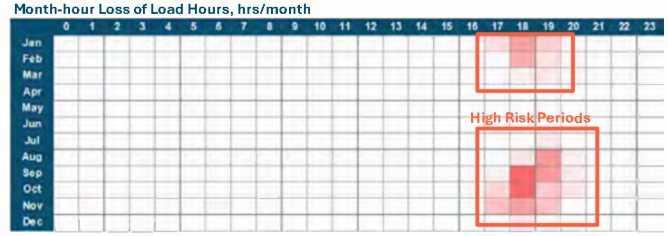


Operational Module

Dispatching resources based on outage characteristics, weather dependency, state of charge availability, and demand-side management

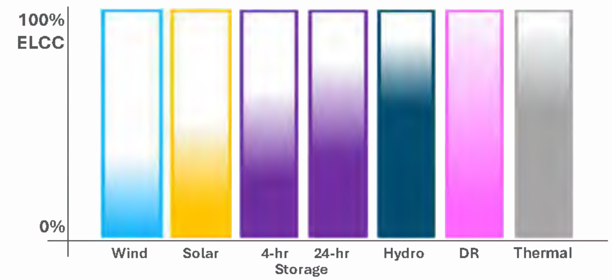
System Reliability: simulates the operations of the electricity system under thousands of scenarios to capture different conditions

Month-hour Loss of Load Hours, hrs/month



Resource Capacity Value: measures resource's ability to contribute to reliability under a marginal or average methodology

Illustrative ELCC Values Across Technologies



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Summary of FPL Resource Adequacy Study (Prepared by E3)
Exhibit AWW-1, Page 6 of 30

RECAP Inputs and Outputs

Inputs

Load
- *Hourly load for many weather years*

Dispatchable Generation
- *Capacity*
- *FOR*
- *Maintenance*

Renewables
- *Capacity*
- *Hourly generation profiles for many weather years*

Hydro
- *Hydro availability for many hydro years*
- *Max/min constraints*

Storage
- *Capacity*
- *Duration*
- *Roundtrip efficiency*
- *FOR*

Demand Response
- *Capacity*
- *Max # of calls*
- *Duration of each call*

Outputs

LOLE
- *Loss of load expectation*
- *days/yr of total expected lost load*

LOLH
- *Loss of load hours*
- *hrs/yr of total expected lost load*

EUE
- *Expected unserved energy*
- *MWh/yr of energy that cannot be served*

ELCC
- *Effective load carrying capability*
- *Equivalent quantity of 'perfect capacity' for a variable or energy-limited resource*

TPRM
- *Target planning reserve margin*
- *PRM required to achieve a specified reliability threshold (i.e. LOLE, ALOLP, or EUE)*

RECAP Workflow

Weather-matched load, wind and solar

Energy-limited resources dispatched time-sequentially

System Demand
(net of EE) simulated hourly across a broad range of weather conditions

Variable Resources
(including BTM PV) simulated with weather-matched hourly profiles

Firm Resources
simulated based on rated capacity and outage rates

Hydroelectric Resources
dispatched based on monthly capacity & energy limits

Storage Resources
dispatched according to limits on duration and round-trip losses

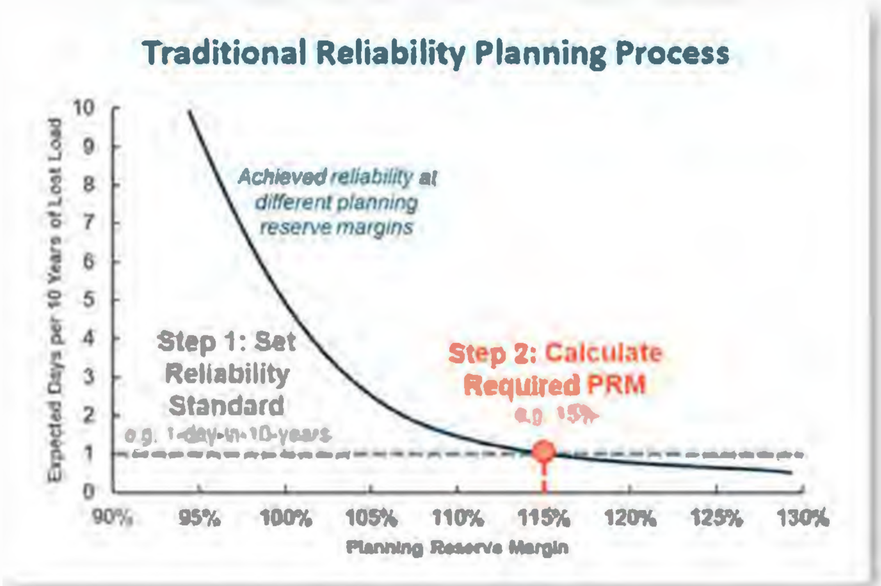
DR Programs
dispatched subject to limits on number of calls & duration

Unserved Energy
identified based on any unmet demand

Each simulation analyzes conditions across hundreds to thousands of possible years using a Monte Carlo approach, where each year captures a different combination of underlying weather, load, wind & solar profiles; outage patterns; and energy-limited resource dispatch

This study calculates FPL's Total Resource Need (TRN) and Target Planning Reserve Margin (Target PRM) that achieves a 0.1 LOLE standard

- **Total Resource Need is the quantity of effective capacity needed to meet a defined reliability standard**
  - Defined for this study as "1 day in 10 years" or Loss-of-Load Expectation ("LOLE") of 0.1 days/yr.
- **PRM is measured as the quantity of capacity needed above the median year peak load to meet the LOLE standard**
  - Calculated as (TRN – Median Peak)/Median Peak
  - Serves as a simple and intuitive metric that can be utilized broadly in power system planning
  - Considers load and resource conditions during *all hours of the year*



Resource adequacy challenges are evolving, necessitating updates to historical analytical methods

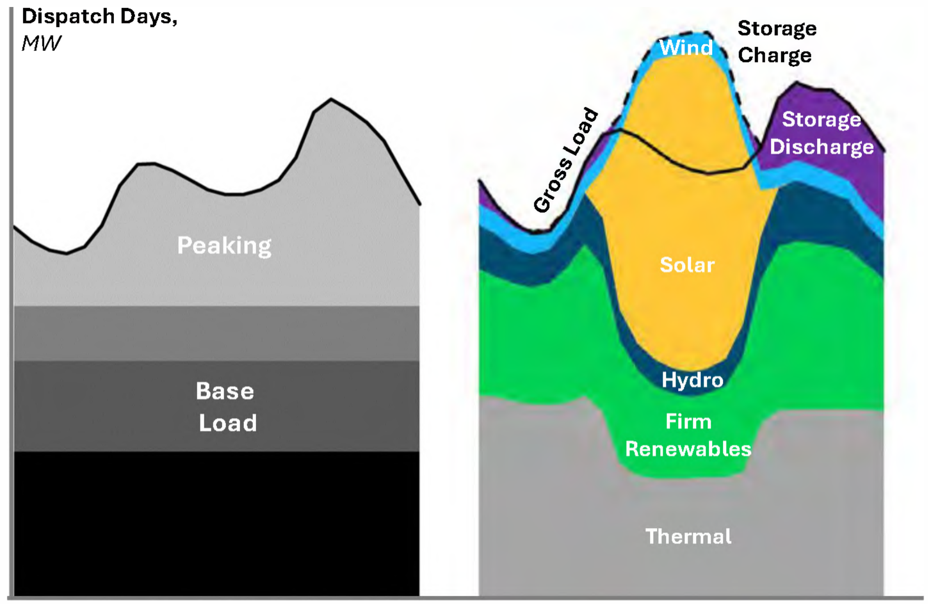
- Traditional resource adequacy planning relies on dispatchable resources to meet gross peak demand
- As renewable penetration grows, planning to meet net peak demand becomes the pivotal challenge
- Capturing thermal fleet unavailability is increasingly important as its capacity value may be affected by correlated outages

Traditional Systems

Are there enough thermal resources to meet gross peak demand?

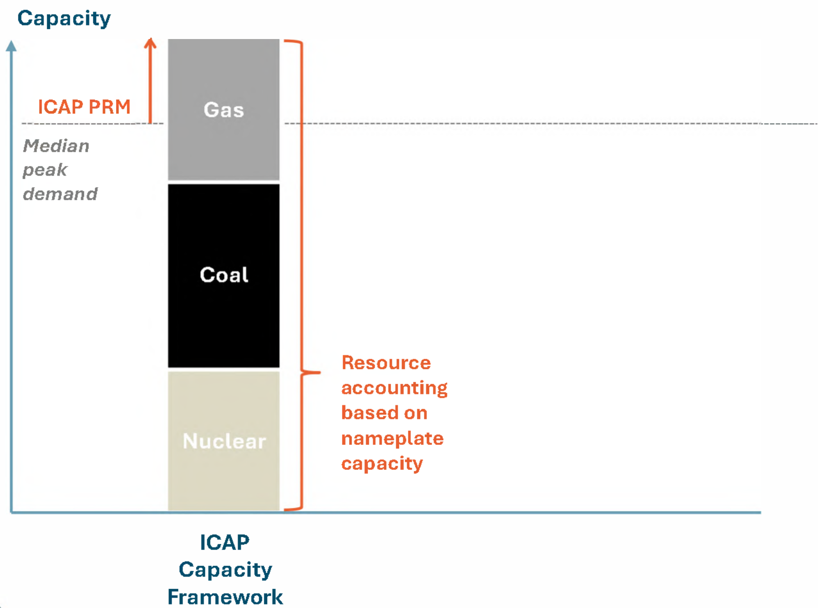
Today and Future Systems

*How does the portfolio of variable, energy-limited, **and** dispatchable resources combine to contribute to reliability?*



Traditionally, resource accreditation was simple with conventional "firm" generating resources

- **PRM defined based on Installed Capacity method (ICAP)**
  - Covers annual peak load variation, operating reserve requirements, and thermal resource forced outages
- **Individual resources accredited based on nameplate capacity**
  - Small differences in forced outage rates
  - No interactions among resources
  - Forced outages also incorporated through performance penalties

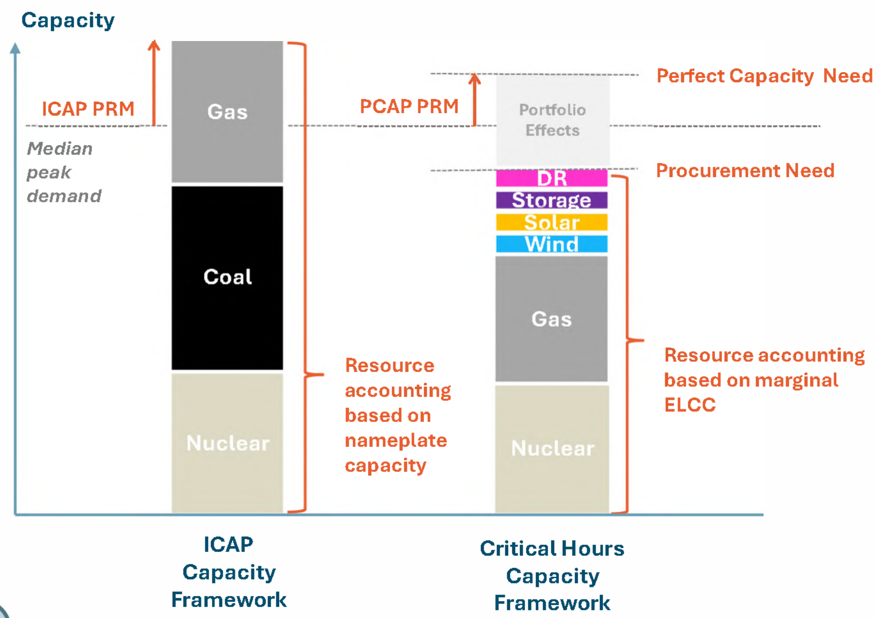


$$Installed\ Capacity = \sum_{i=1}^{n} G_i$$

ELCC approach adapts the PRM framework for a more diverse resource mix and calculates each resource type's contribution to the Total Resource Need

- **PRM defined based on need for Equivalent Perfect Capacity (PCAP)**
  - Covers annual peak load variation and operating reserves only; forced outages addressed in resource accreditation
- **Individual resources accredited based on ELCC**
  - Large differences in availability during key hours
  - Significant interactions among resources
  - ELCC values are dynamic based on resource portfolio

$$Portfolio\ ELCC = f(G_1, G_2, \ldots, G_n)$$



Measuring ELCC of a portfolio and individual resources

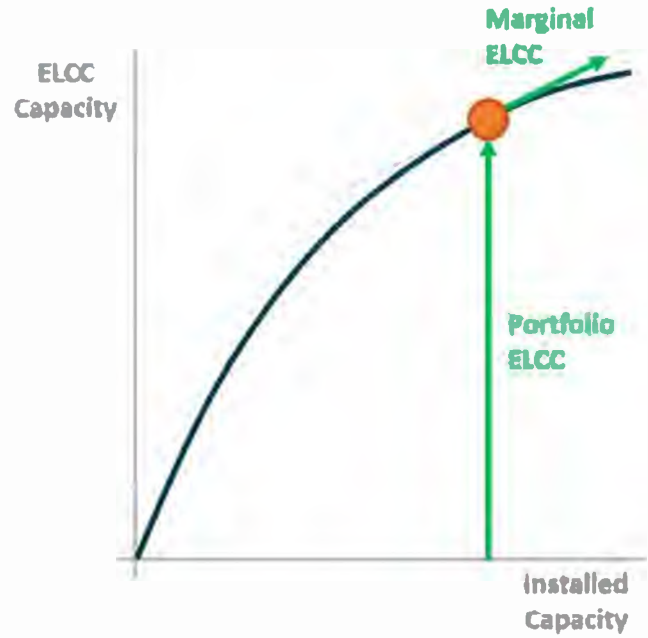
- **ELCC is a function of the portfolio of resources**
  - The function is a surface in multiple dimensions
  - The Portfolio ELCC is the height of the surface at the point representing the total portfolio

$$Portfolio\ ELCC = f(G_1, G_2, \ldots, G_n)\ (MW)$$

  - The Marginal ELCC of any individual resource is the gradient (or slope) of the surface along a single dimension – mathematically, the partial derivative of the surface with respect to that resource

$$Marginal\ ELCC_{G_1} = \frac{\partial f}{\partial G_1}(G_1, G_2 \ldots G_n)\ (\%)$$

- **The functional form of the surface is unknowable**
  - Marginal ELCC calculations give us measurements of the contours of the surface at specific points
  - It is impractical to map out the entire surface



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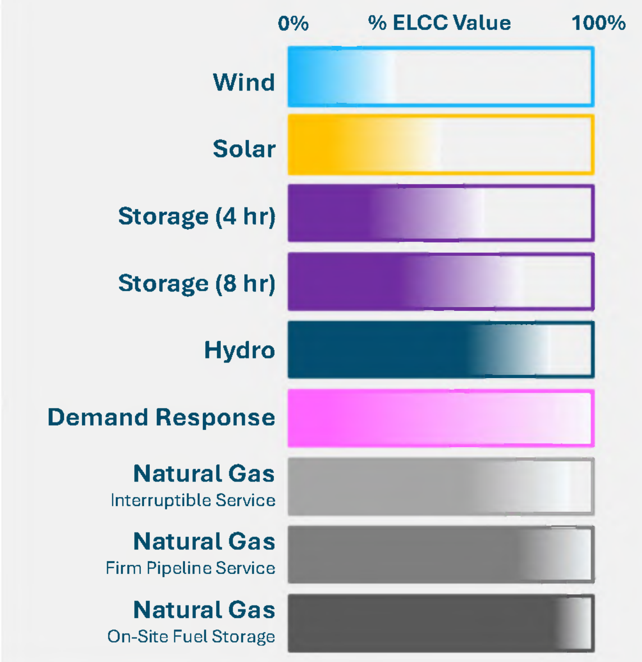
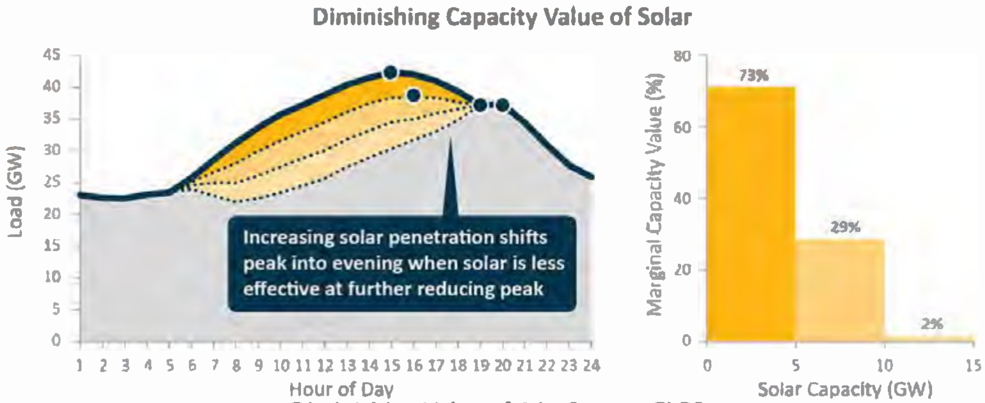
E3 used a marginal ELCC methodology to calculate each resource type's incremental contribution to system resource adequacy

- **No resource is "perfect": ELCC measures all resources against equivalent perfect capacity**
  - Demand response also accredited using ELCC based on modeled performance during critical hours
- **Accounts for all factors that can limit availability:**
  - Hourly variability in output
  - Duration and/or use limitations
  - Temperature-related derates
  - Temperature-related forced outage rates
  - Energy availability
  - Correlated outage risk
- **Uses Perfect Capacity (PCAP) accounting as opposed to ICAP or UCAP**

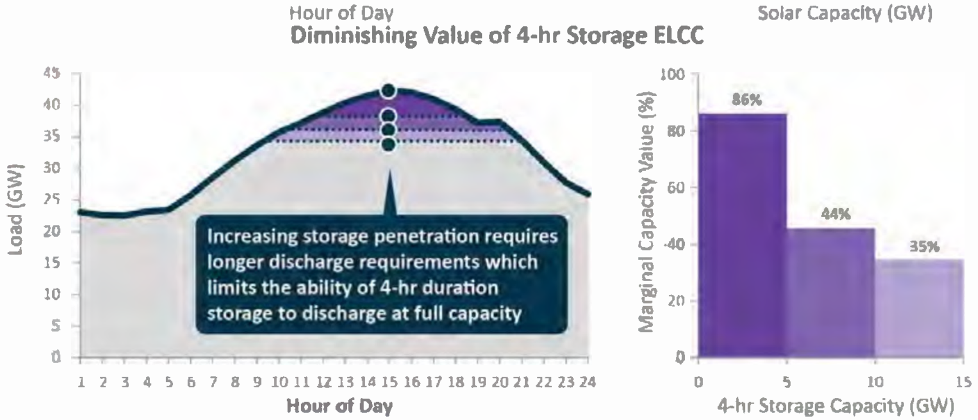
Illustrative ELCC Values Across Technologies



RECAP's ELCC calculations capture diminishing capacity contribution of variable and dispatch-limited resources at higher penetrations



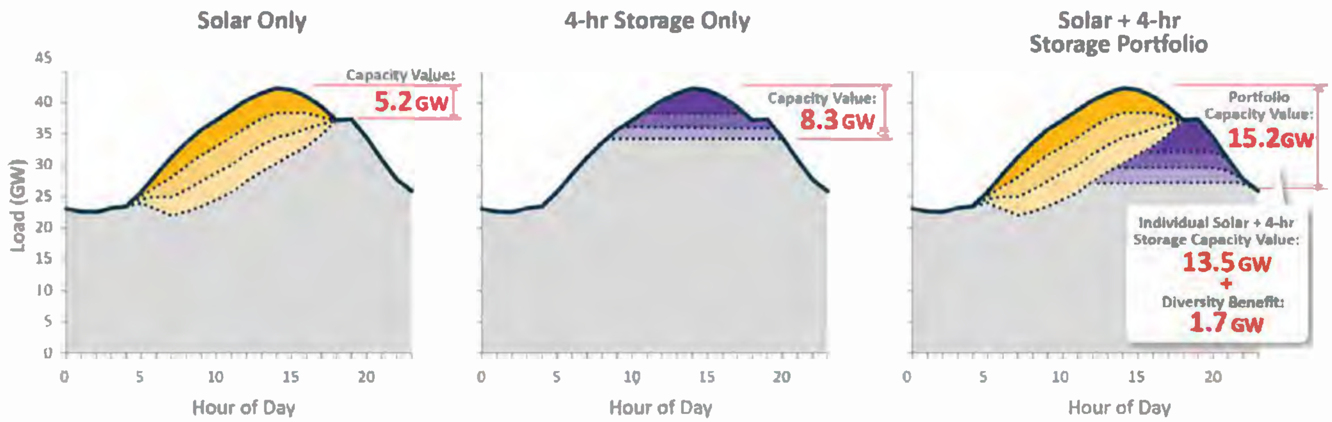
Solar and other **variable resources** exhibit declining value due to variability of production profiles



Storage and other **energy-limited resources** (e.g. DR) exhibit declining value due to limited ability to generate over sustained periods

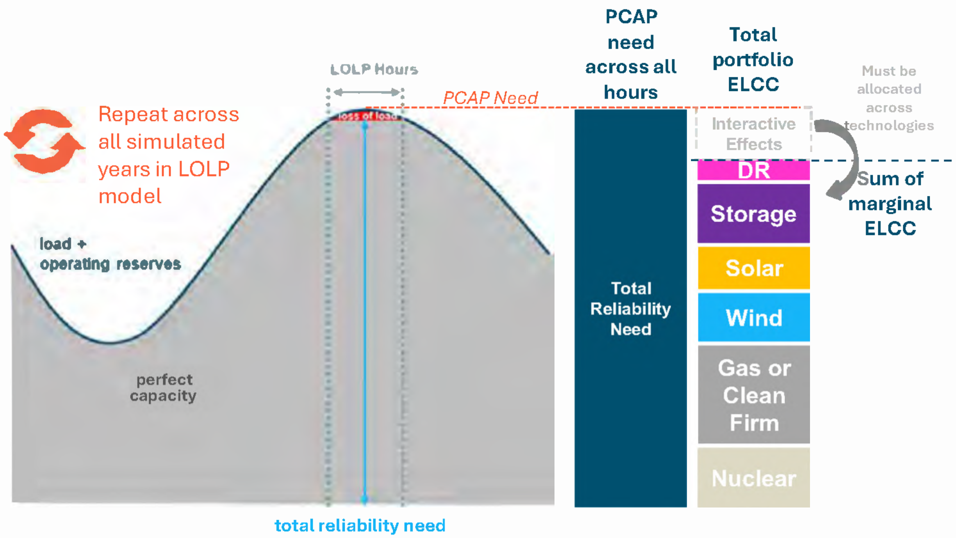
RECAP's ELCC calculations capture interactive or "portfolio" effects from the addition of different types of resources to the portfolio

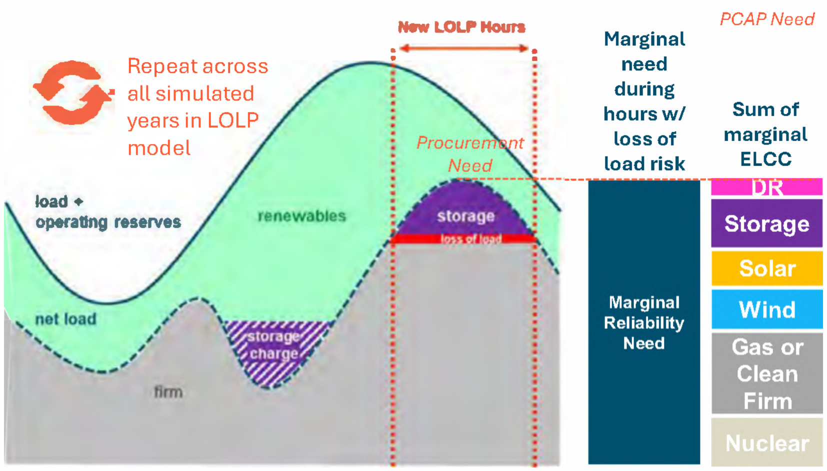
- Different types of resources interact with each other, creating portfolio effects in which the total ELCC derived from the portfolio is greater than the sum of marginal ELCC values from individual resources
- Resources with similar characteristics may compete with each other, leading to more rapid marginal ELCC declines
- As penetrations of intermittent and energy-limited resource grow, the magnitude of these interactive effects increases and becomes a significant factor in system planning



RECAP's ELCC calculations capture the shifting of critical hours from "gross peak" to "net peak" resulting from higher penetrations of solar energy

- On a system with conventional resources, resource adequacy events typically coincide with peak load periods
- ICAP accreditation is independent of the timing of peak load needs
- On a system with high solar penetration, resource adequacy events typically occur after sundown when solar generation is low
- Marginal ELCC accreditation captures resource performance during these new critical hours





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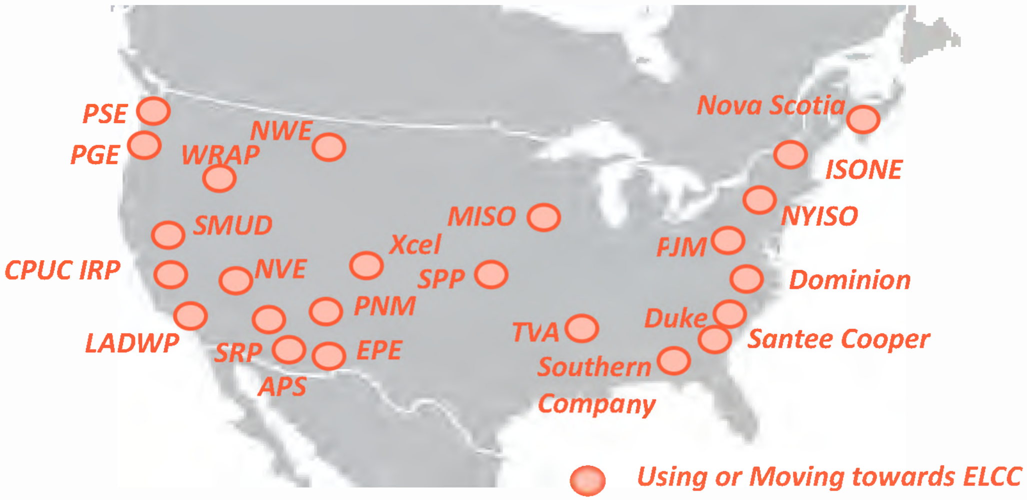
ELCC is increasingly used by utilities and ISOs across the country

- Many ISO/RTOs and utilities are already using or considering a transition to ELCC for renewable (e.g., solar, wind) and/or energy limited resources (e.g., storage)



Resource Adequacy Study Results for Florida Power & Light

Energy+Environmental Economics

Reliability Results Summary

Model Year	Median Peak Load	Perfect Capacity Reserve Margin Target	Total Reliability Need	Portfolio Capacity Value (ELCC Methodology)	Capacity Shortfall	Achieved Loss of Load Expectation
	MW	*% of Peak*	*Firm MW*	*Firm MW*	*Firm MW*	*Days per Year*
2027 TYP *+1,400MW Batteries*	29,708	8.8%	32,322	32,049	(273)	0.11
2028	30,283		32,948	32,929	(19)	0.10
2029	30,831		33,544	33,440	(104)	0.13
2030	31,344		34,102	33,991	(112)	0.13
2035	34,847		37,914	36,696	(1,218)	0.33
Derivation:	*A*	*B*	*C = A x (1+B)*	*D*	*E = D – C*	*F*

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Load & Resources Table 2027 – Ten-Year Site Plan (TYP) Portfolio

	LOLP-Derived Methodology	2027		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,281	25,197	89%
2	Utility Solar (Fixed + Tracking)	8,946	1,407	16%
3	Behind-the-meter (BTM) Solar[1]	2,125	83	4%
4	Storage	991	923	93%
5	Demand Response (DR)	1,951	1,703	87%
6	Portfolio Effect/Peak to Net Load Shift		1,348	
7	**Portfolio ELCC** *(E3 Methodology)*	42,294	30,659	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	29,708		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,322		
12	Firm Capacity Surplus / Shortfall	*-1663*		

- **All resource accredited using a marginal ELCC methodology**
- **For 2028 and beyond, utility solar and BTM solar marginal ELCC is derived from a single marginal solar value, allocated out based on the 2027 marginal values**
- **For 2028 and beyond, Storage and DR marginal ELCC is derived from a single marginal storage value, allocated out based on the 2027 marginal storage and DR values**

1) MW AC, assuming ILR = 1/0.85

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Exhibit AWW-1, Page 21 of 30

Load & Resources Table 2027 – TYP Portfolio +1,400 MW of Storage

LOLP-Derived Methodology

		2027 +1,400 MW of Storage		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,281	25,197	89%
2	Utility Solar (Fixed + Tracking)	8,946	1,516	17%
3	Behind-the-meter (BTM) Solar[1]	2,125	169	8%
4	Storage	***2,391***	1,808	76%
5	Demand Response (DR)	1,951	1,584	81%
6	Portfolio Effect/Peak to Net Load Shift		1,775	
7	**Portfolio ELCC** *(E3 Methodology)*	43,694	32,049	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	29,708		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,322		
12	Firm Capacity Surplus / Shortfall	*-273*		

- **Additional 1,400 Nameplate MW of Storage relative to the 2027 TYP portfolio**
- **This reduces the capacity shortfall by 1,390 Firm MW**
- **Marginal ELCC of solar is higher with more storage**
- **Marginal ELCC of storage and DR is lower with higher storage penetration**

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2028

	LOLP-Derived Methodology	2028		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,362	25,269	89%
2	Utility Solar (Fixed + Tracking)	9,840	1,424	14%
3	Behind-the-meter (BTM) Solar[1]	2,593	176	7%
4	Storage	3,211	1,596	50%
5	Demand Response (DR)	1,945	1,038	53%
6	Portfolio Effect/Peak to Net Load Shift		3,425	
7	**Portfolio ELCC** *(E3 Methodology)*	45,951	32,929	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	30,283		
9	Median Peak Demand less DR	Not used		
10	**PCAP** Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	32,948		
12	Firm Capacity Surplus / Shortfall	*-19*		

- **Requirement grows by 626 MW due to load growth**
- **Resources added:**
  - 81 MW more thermal
  - 1,362 MW more solar reduces marginal ELCC by 1-3 percent
  - 820 MW more storage reduces marginal ELCC by 26 percent
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2029

	LOLP-Derived Methodology	2029		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,197	25,122	89%
2	Utility Solar (Fixed + Tracking)	11,628	1,230	11%
3	Behind-the-meter (BTM) Solar[1]	3,118	155	5%
4	Storage	3,807	1,614	42%
5	Demand Response (DR)	1,945	885	46%
6	Portfolio Effect/Peak to Net Load Shift		4,434	
7	**Portfolio ELCC** *(E3 Methodology)*	48,695	33,440	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	30,831		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	33,544		
12	Firm Capacity Surplus / Shortfall	*-104*		

- **Requirement grows by 596 MW due to load growth**
- **Resource changes from 2028:**
  - 165 MW less thermal
  - 2,313 MW more solar reduces marginal ELCC by 2-3 percent
  - 596 MW more storage reduces marginal ELCC by 8 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2030

	LOLP-Derived Methodology	2030		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	28,194	25,119	89%
2	Utility Solar (Fixed + Tracking)	13,416	897	7%
3	Behind-the-meter (BTM) Solar[1]	3,704	116	3%
4	Storage	4,403	1,647	37%
5	Demand Response (DR)	1,944	781	40%
6	Portfolio Effect/Peak to Net Load Shift		5,430	
7	**Portfolio ELCC** *(E3 Methodology)*	51,661	33,991	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	31,344		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	34,102		
12	Firm Capacity Surplus / Shortfall	*-112*		

+ **Requirement grows by 558 MW due to load growth**
+ **Resource changes from 2029:**
  - 3 MW less thermal
  - 2,374 MW more solar reduces marginal ELCC by 4-8 percent
  - 596 MW more storage reduces marginal ELCC by 5 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

1) MW AC, assuming ILR = 1/0.85

Load & Resources Table 2035

LOLP-Derived Methodology		2035		
		Nameplate Capacity (MW)	Firm Capacity (MW)	Firm Capacity (% of Nameplate)
1	Thermal + Kingfisher 1/2	27,942	24,895	89%
2	Utility Solar (Fixed + Tracking)	24,517	382	2%
3	Behind-the-meter (BTM) Solar[1]	7,244	53	1%
4	Storage	7,383	1,786	24%
5	Demand Response (DR)	1,945	505	26%
6	Portfolio Effect/Peak to Net Load Shift		9,074	
7	**Portfolio ELCC** *(E3 Methodology)*	69,031	36,696	
8	Median Peak Demand **(Grossed up for BTM PV & Net of Energy Efficiency)**	34,847		
9	Median Peak Demand less DR	Not used		
10	PCAP Planning Reserve Margin (PRM)	8.8%		
11	Total Firm MW Requirement	37,914		
12	Firm Capacity Surplus / Shortfall	*-1,218*		

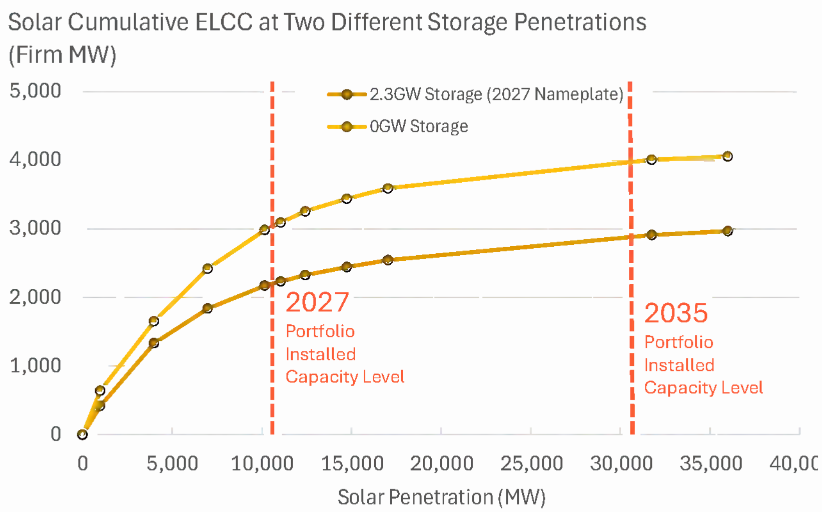
- **Requirement grows by 3,812 MW due to load growth**
- **Resource changes from 2030:**
  - 252 MW less thermal
  - 14,641 MW more solar reduces marginal ELCC to 2 percent
  - 2,980 MW more storage reduces marginal ELCC to 24 percent
  - DR marginal ELCC is also reduced due to higher storage penetration
  - Larger portfolio effect due to increased solar-storage penetration, diminished marginal ELCCs, and lower net peak loads during critical hours

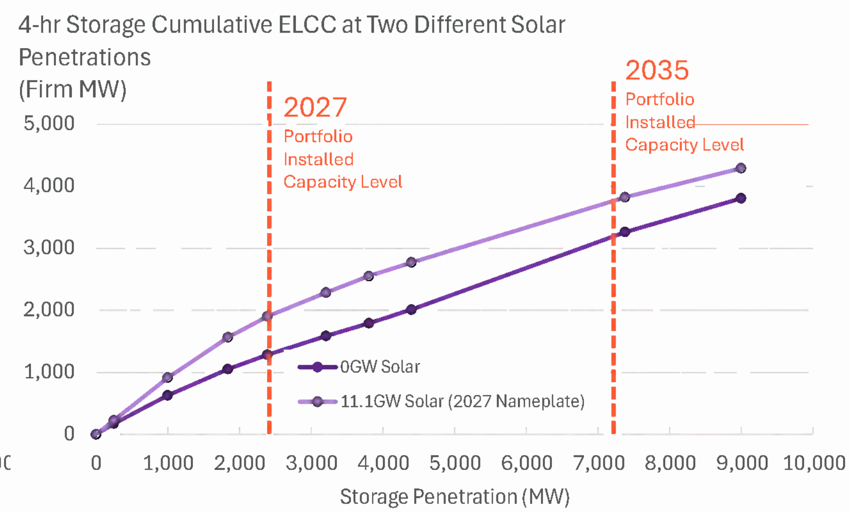
1) MW AC, assuming ILR = 1/0.85

Effective Load Carrying Capability Results

Energy+Environmental Economics

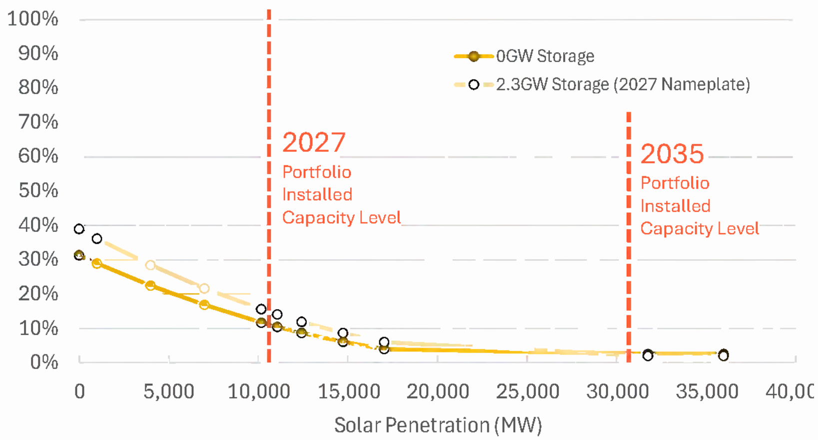
Solar and Storage Cumulative ELCC (Firm MW)



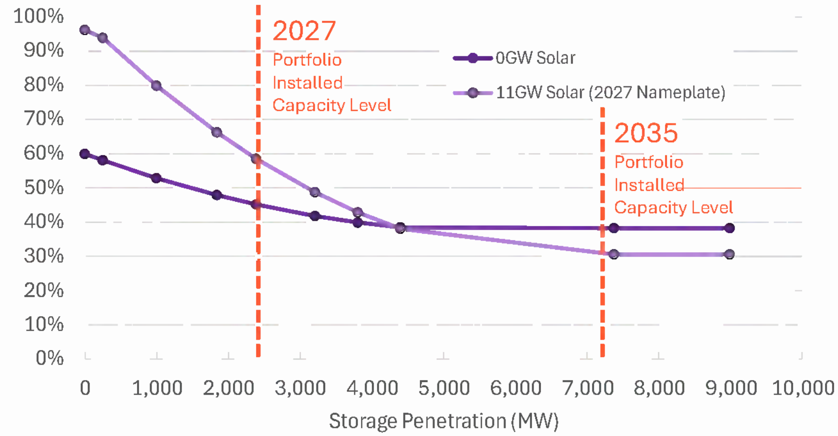


Solar and Storage Marginal ELCC (% of Nameplate MW)

Solar Marginal ELCC at two Different Storage Penetrations
(% of Solar Nameplate Capacity)



4-hr Storage Marginal ELCC at Three Different Solar Penetrations
(% of Storage Nameplate Capacity)



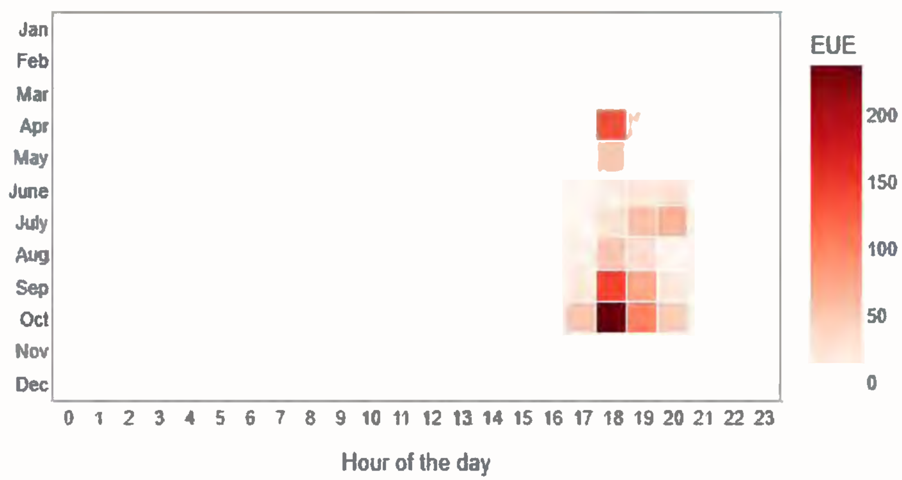
Docket No. 20250011-EI
Summary of FPL Resource Adequacy Study (Prepared by E3)
Exhibit AWW-1, Page 29 of 30

LOLP Heat Map in 2027

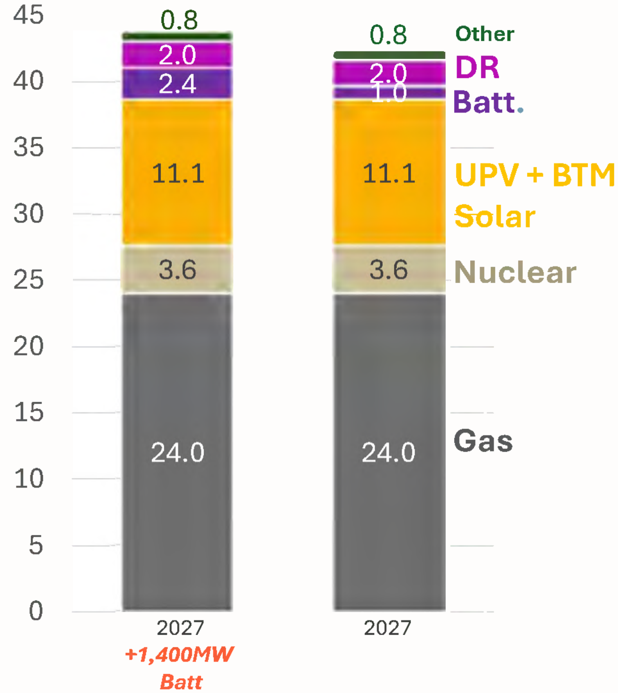
+ Observations

- Loss of load risk is mostly concentrated in summer evenings
- Outages also occur during shoulder months (spring and fall) when maintenance and forced outages occur simultaneously
- Loss of load occurs in late evenings, or during low solar periods

2027 Month-Hour Average Unserved Energy, *(MWh)*



2027 Portfolios,
Nameplate MW



Docket No. 20250011-EI
Summary of FPL Resource Adequacy Study (Prepared by E3)
Exhibit AWW-1, Page 30 of 30

Docket No. 20250011-EI
Load Forecasts Used in the Current Analyses
Exhibit AWW-2, Page 1 of 1

Load Forecasts Used in the Current Analyses*

	(1)	(2)	(3)
Year	**Summer Peak (MW)**	**Winter Peak (MW)**	**Net Energy For Load (GWh)**
2025	28,312	23,042	144,793
2026	28,664	23,323	144,931
2027	28,925	23,648	145,905
2028	29,333	24,136	148,562
2029	29,687	24,603	150,976
2030	29,982	25,011	153,094
2031	30,301	25,384	154,375
2032	30,823	25,852	156,728
2033	31,257	26,245	158,922
2034	31,677	26,638	160,473
2035	32,112	27,045	162,209
2036	32,547	27,461	164,006
2037	32,962	27,873	165,643
2038	33,356	28,281	167,117
2039	33,709	28,676	168,417
2040	34,027	29,060	169,482
2041	34,285	29,422	170,443
2042	34,348	29,590	169,858
2043	34,562	29,938	170,506
2044	34,731	30,269	170,984
2045	34,904	30,421	171,836
2046	35,078	30,573	172,692
2047	35,252	30,726	173,554
2048	35,427	30,880	174,419
2049	35,604	31,035	175,289
2050	35,781	31,190	176,163
2051	35,959	31,346	177,042
2052	36,138	31,503	177,926
2053	36,318	31,661	178,814
2054	36,499	31,820	179,707
2055	36,681	31,979	180,604
2056	36,863	32,140	181,506
2057	37,047	32,301	182,413
2058	37,232	32,463	183,324
2059	37,417	32,626	184,240
2060	37,604	32,789	185,161
2061	37,791	32,954	186,086
2062	37,980	33,119	187,016
2063	38,169	33,286	187,952
2064	38,360	33,453	188,891
2065	38,551	33,621	189,836
2066	38,743	33,790	190,786
2067	38,937	33,959	191,740
2068	39,131	34,130	192,700
2069	39,327	34,301	193,665
2070	39,523	34,474	194,634
2071	39,720	34,647	195,608

* Load forecasts used in resource planning analyses do not include the projected impacts of existing load management programs or of incremental load management and energy conservation utility DSM programs. Those impacts are addressed as line item adjustments to the load forecasts in the resource planning models.

Docket No. 20250011-EI
Fuel Cost Forecasts Used in the Current Analyses
Exhibit AWW-3, Page 1 of 1

Fuel Cost Forecasts Used in the Current Analyses
(September 3, 2024 Forecast, Nominal $)

Year	FGT Firm Gas ($/MMBTU)	Gulfstream Firm Gas ($/MMBTU)	Sabal Trail Firm Gas ($/MMBTU)	Residual Oil ($/MMBTU)	Distillate Oil ($/MMBTU)	Scherer 3 Coal Price ($/MMBTU)
2025	3.34	3.24	3.73	13.86	17.41	3.12
2026	3.77	3.60	4.24	13.38	17.26	3.20
2027	4.59	4.34	4.82	14.21	17.96	3.28
2028	4.70	4.37	4.73	14.45	18.42	3.62
2029	5.05	4.68	5.04	16.08	20.02	3.68
2030	5.11	4.72	5.10	16.17	20.48	3.70
2031	5.15	4.76	5.14	16.13	20.76	3.75
2032	5.43	5.05	5.42	16.22	21.10	3.80
2033	5.90	5.52	5.88	16.33	21.54	3.85
2034	6.12	5.73	6.09	16.37	21.96	3.90
2035	6.60	6.21	6.56	16.39	22.28	3.94
2036	6.82	6.43	6.78	16.41	22.66	3.99
2037	6.90	6.50	6.85	16.42	22.97	4.04
2038	7.05	6.66	7.01	16.52	23.50	4.10
2039	7.25	6.86	7.20	16.53	23.90	4.17
2040	7.62	7.22	7.56	16.58	24.45	4.24
2041	7.94	7.54	7.87	16.62	24.78	4.31
2042	8.19	7.79	8.12	16.64	25.31	4.38
2043	8.52	8.12	8.44	16.65	25.74	4.45
2044	8.74	8.34	8.66	16.67	26.34	4.52
2045	9.12	8.71	9.03	16.68	26.89	4.61
2046	9.90	9.49	9.79	16.68	27.38	4.68
2047	10.46	10.05	10.34	16.69	27.88	4.76
2048	11.05	10.64	10.92	16.69	28.39	4.85
2049	11.63	11.22	11.50	16.69	28.95	4.95
2050	12.33	11.92	12.18	16.72	29.58	5.05
2051	12.28	11.87	12.13	16.71	29.67	5.14
2052	12.23	11.81	12.08	16.69	29.76	5.24
2053	12.18	11.76	12.03	16.68	29.84	5.34
2054	12.13	11.71	11.98	16.67	29.93	5.43
2055	12.08	11.66	11.93	16.66	30.02	4.25
2056	12.03	11.61	11.88	16.65	30.12	5.63
2057	11.98	11.56	11.83	16.63	30.21	5.72
2058	11.92	11.51	11.78	16.62	30.30	5.82
2059	11.87	11.46	11.73	16.61	30.39	5.92
2060	11.82	11.41	11.68	16.60	30.48	6.01
2061	11.78	11.36	11.64	16.58	30.57	6.11
2062	11.73	11.31	11.59	16.57	30.66	6.21
2063	11.68	11.26	11.54	16.56	30.76	6.30
2064	11.63	11.21	11.49	16.55	30.85	6.40
2065	11.58	11.16	11.44	16.54	30.94	6.50
2066	11.53	11.12	11.39	16.52	31.03	6.59
2067	11.48	11.07	11.35	16.51	31.13	6.69
2068	11.43	11.02	11.30	16.50	31.22	6.79
2069	11.38	10.97	11.25	16.49	31.32	6.88
2070	11.34	10.92	11.21	16.48	31.41	6.98
2071	11.29	10.88	11.16	16.46	31.51	7.08

CO_2 Compliance Cost Forecast Used in the Current Analyses
(2022 Q4 ICF Forecast, Nominal $)

Year	CO_2 Cost ($/ton)
2025	0.0
2026	0.0
2027	0.0
2028	0.0
2029	0.0
2030	0.0
2031	0.0
2032	0.0
2033	0.0
2034	0.0
2035	0.0
2036	3.3
2037	6.7
2038	10.3
2039	14.1
2040	18.0
2041	20.6
2042	23.7
2043	27.2
2044	31.3
2045	36.0
2046	40.1
2047	44.7
2048	49.9
2049	55.7
2050	62.1
2051	63.4
2052	64.7
2053	66.1
2054	67.5
2055	68.9
2056	70.3
2057	71.8
2058	73.3
2059	74.9
2060	76.4
2061	78.0
2062	79.7
2063	81.4
2064	83.1
2065	84.8
2066	86.6
2067	88.4
2068	90.3
2069	92.2
2070	94.1
2071	96.1

Economic Analysis Results for the Proposed 2026 and 2027 Solar And Battery Additions

Common to all Plans Retirements / Additions	Year	Without Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)	With Proposed 2026 and 2027 Solar And Battery Additions	Reserve Margin (%)
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL	22.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1
Broward South (4 MW)	2027	---	21.1	1,192 MW Solar 819.5 MW Battery	27.2
Lansing Smith A (32 MW)	2028	1 x 2x0 Manatee CT (475 MW)	21.0	---	25.3
---	2029	1 x 2x0 Manatee CT (475 MW)	21.2	---	23.8
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	1 x 2x0 Manatee CT (475 MW)	21.1	---	22.0
---	2031	1 x 2x0 Manatee CT (475 MW)	21.5	---	20.7
---	2032	1 x 2x0 Manatee CT (475 MW)	20.9	1 x 2x0 Manatee CT (475 MW)	20.0
---	2033	1 x 2x0 Manatee CT (475 MW)	20.8	2 x 2x0 Manatee CT (950 MW)	21.6
---	2034	1 x 2x0 Manatee CT (475 MW)	20.5	1 x 2x0 Manatee CT (475 MW)	21.2

	Without Proposed Solar and Battery Additions	With Proposed Solar and Battery Additions
CPVRR Costs =	**$108,841**	**$106,899**
CPVRR Costs Difference from the Without Proposed Solar and Battery Additions Plan =	**--**	**($1,942)**

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers
Analysis assumes new CT capacity is available in 2028 to put plans on equal footing; realistically new CT installations would not be available until late 2029 or early 2030 at the earliest

Docket No. 20250011-EI
Economic Analysis Results for the Combined 2026 and 2027 Solar and Battery Additions
Exhibit AWW-5, Page 1 of 1

Economic Analysis Results for the Proposed 2028 and 2029 Solar And Battery Additions

Common to all Plans Retirements / Additions	Year	Without Proposed 2028-2029 Solar And Battery Additions	Reserve Margin (%)	With Proposed 2028-2029 Solar And Battery Additions	Reserve Margin (%)
Pea Ridge (12 MW)	2025	894 MW Solar	22.4	894 MW Solar	22.4
---	2026	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1	522 MW Battery NWFL 894 MW Solar 1,419.5 MW Battery	24.1
Broward South (4 MW)	2027	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar 819.5 MW Battery	27.2
Lansing Smith A (32 MW)	2028	---	25.3	1,490 MW Solar 596 MW Battery	26.6
---	2029	---	23.8	1,788 MW Solar 596 MW Battery	26.3
GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2030	---	22.0	---	24.5
---	2031	---	20.7	---	23.2
---	2032	1 x 2x0 Manatee CT (475 MW)	20.0	---	20.9
---	2033	2 x 2x0 Manatee CT (950 MW)	21.6	1 x 2x0 Manatee CT (475 MW)	20.8
---	2034	1 x 2x0 Manatee CT (475 MW)	21.2	1 x 2x0 Manatee CT (475 MW)	20.5

	Without Proposed	With Proposed
CPVRR Costs =	**$106,899**	**$104,686**
CPVRR Costs Difference from the Without Proposed 2028-2029 Solar and Battery Additions Plan =	**--**	**($2,213)**

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071
Negative values indicate CPVRR savings to customers

Docket No. 20250011-EI
Economic Analysis Results for the Combined 2028 and 2029 Solar and Battery Additions
Exhibit AWW-6, Page 1 of 1

With Programs and Without Programs Resource Plans for CDR and CILC Incentive Payment Analysis

	(1)	(2)	(3)	(4)	(5)
Year	**Common to All Plans** **Retirements/Additions**	**"With Programs" Resource Plan**	**Reserve Margin (%)**	**"Without Programs" Resource Plan**	**Reserve Margin (%)**
2025	Pea Ridge (12 MW)	894 MW Solar	22.4	894 MW Solar	22.4
2026	---	894 MW Solar 522 MW Battery in NWFL 1,419.5 MW Battery	24.1	894 MW Solar 522 MW Battery in NWFL 1,519.5 MW Battery	20.1
2027	Broward South (4 MW)	1,192 MW Solar 819.5 MW Battery	27.2	1,192 MW Solar 819.5 MW Battery	23.1
2028	Lansing Smith A (32 MW)	1,490 MW Solar 596 MW Battery	26.6	1,490 MW Solar 596 MW Battery	22.6
2029	---	1,788 MW Solar 596 MW Battery	26.3	1,788 MW Solar 596 MW Battery	22.3
2030	GCEC 4 (75 MW), GCEC 5 (75 MW), Perdido 1&2 (3 MW)	2,235 MW Solar 596 MW Battery	25.8	2,235 MW Solar 596 MW Battery	21.8
2031	---	2,235 MW Solar 596 MW Battery	25.7	2,235 MW Solar 596 MW Battery	21.8
2032	---	2,235 MW Solar 596 MW Battery	24.5	2,235 MW Solar 596 MW Battery	20.7
2033	---	2,235 MW Solar 596 MW Battery	23.9	2,235 MW Solar 820 MW Battery	20.3
2034	---	2,235 MW Solar 596 MW Battery	23.0	2,235 MW Solar 2,980 MW Battery	21.4
	CPVRR Cost of Resource Plans =	**$99,322**		**$100,390**	
	CPVRR Impact for Removing CDR + CILC =	---		**$1,069**	

Notes:
CPVRR costs are in million $ and are discounted at 8.15% (FPL's most recent WACC) for the years 2025 thru 2071

Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs

Assumptions:	
Assumption (1): Projected CPVRR Net Benefits for CDR & CILC (millions)	$1,069
Assumption (2): CPVRR Admin Costs (millions)	$10
Assumption (3): Current CDR Monthly Incentive Level ($/kW)	$8.76
Assumption (4): Discount rate	8.15%
Assumption (5): Average Monthly MW of CDR & CILC	792
Assumption (6): Time Period Over Which CPVRR Costs are Calculated	2025 thru 2071
Assumption (7): CPVRR Cost of $1/kW Monthly Incentive Payment for 1 MW (see calculation below)	$143,232

	(1)	(2)	(3)	(4)
		= (Monthly Incentive x Assumption 5 x Assumption 7) /1,000,000	= (2) + Assumption 2	= (1) / (3)
Scenario	**CPVRR Net Benefits (Millions)**	**CPVRR Cost of Incentives Only (Millions)**	**CPVRR Total Cost: Incentives + Admin Costs (Millions)**	**RIM Benefit-to-Cost Ratio**
Scenario 1: With Current Monthly Incentive Level of $8.76/kW:	$1,069	$994	$1,004	**1.06**
Scenario 2: With Proposed Monthly Incentive Level of $6.22/kW:	$1,069	$706	$716	**1.49**

Year	**Annual Incentive Cost for 1 MW at $1/kW-mo.**
2025	$0
2026	$12,000
2027	$12,000
2028	$12,000
2029	$12,000
2030	$12,000
2068	$12,000
2069	$12,000
2070	$12,000
2071	$12,000
CPVRR =	**$143,232**

(Note: rows for years 2031 thru 2067 are not shown to save space; those annual values are identical to the annual values that are shown.)

Docket No. 20250011-EI
Analysis of the Current and Proposed Monthly Incentive Levels for the CDR & CILC Programs
Exhibit AWW-8, Page 1 of 1

APPENDIX 3

REPORT AND AFFIDAVIT OF DR. JOHN MORRIS

[See Attached]

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C. Florida Power & Light Company, Inc.	)))	Docket No. EC25-____-000

Report and Affidavit of
Dr. John R. Morris

June 10, 2025

Secretariat

Florida Power & Light Company, Inc's Acquisition of the Vandolah Facility

Executive Summary

Florida Power & Light Company, Inc. ("FPL"), along with Vandolah Power Company L.L.C., is filing for authority under Section 203 of the Federal Power Act ("FPA") to acquire the Vandolah Peaking Power Facility ("Vandolah") in Wauchula, Hardee County, Florida. Vandolah is a 660 MW (Summer capacity), dual fuel, peaking plant owned by Vandolah Power Company L.L.C., a subsidiary of Northern Star Generation LLC, comprised of four GE 7FA SC turbines and related equipment. The plant is in the Duke Energy Florida ("DEF") Balancing Authority Area ("BAA"), and it is fully contracted under a tolling agreement with DEF through May 2027. In connection with this filing, counsel for FPL asked Dr. John R. Morris of Secretariat Advisors LLC ("Secretariat") to prepare a generation market power study to determine whether the transaction (the "Transaction") would create or enhance market power in wholesale power markets.

After the Transaction, FPL plans to directly interconnect with Vandolah and incorporate Vandolah into the FPL BAA. Accordingly, Dr. Morris evaluated the FPL BAA and all first-tier areas in Florida as destination markets. He applied the Commission's Delivered Price Test ("DPT") and calculated Herfindahl-Hirschman Indices ("HHIs") as an initial screen. Although the resulting HHI changes exceed the Commission's screening thresholds in some destination markets during certain periods, the screen failures are driven by an increase in Available Economic Capacity ("AEC"), rather than the elimination of a competitor. Moreover, Dr. Morris found that the HHI changes are comparable to those observed in his "But-for" scenario, where FPL meets its future load obligations by constructing new supply instead of acquiring Vandolah.

FPL proposes in its FPA section 203 application temporary mitigation measures to alleviate any potential anticompetitive concerns. At the request of FPL, Dr. Morris studied the effect of the proposed mitigation measures and found no adverse competitive impact in destination markets after the proposed mitigation measures.

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Power & Light Company's Acquisition of the Vandolah Facility

1. Introduction

My name is Dr. John R. Morris. I am a Managing Director at Secretariat Advisors LLC ("Secretariat"), a consulting firm located at 2121 K Street NW, Washington, DC 20037. I received a bachelor's degree in economics from Georgetown University and a master's degree and a Ph.D. in economics from the University of Washington. My primary field is industrial organization, which is the study of company behavior in competitive, oligopolistic, and monopolistic markets. This field also covers the business regulation of companies through the antitrust laws and the price and entry regulation of electric and natural gas utilities.

I have been studying and consulting in the energy industry since joining the Federal Trade Commission in 1985. At the Federal Trade Commission, I served as a staff economist, a Commissioner Advisor, and as the Assistant to the Deputy Director for Antitrust. As a staff economist, I focused much of my time on investigations of the natural gas industry and became familiar with rate-setting principles in that industry at both the federal and state level.

Since joining what is now Secretariat in 1992, I have consulted on many matters involving electric and natural gas companies, examined issues relating to utility rates, examined issues concerning undue discrimination by operators of natural gas and electric power transmission facilities, calculated damages, and calculated amounts of alleged unjust enrichment. I have worked for a wide range of clients including many governmental entities—e.g., the Antitrust Division of the U.S. Department of Justice, the Federal Trade Commission, the City of San Antonio, the City of San Diego, and the New Jersey Board of Public Utilities—and many major corporations—e.g., American Electric Power, Berkshire Hathaway Energy, Energy Transfer, Exelon Corporation, Public Service Electric & Gas, Tampa Electric

Company, TransCanada Corporation, and WEC Energy Group. The Federal Energy Regulatory Commission ("the Commission" or "FERC"), state public utility commissions, and federal courts have accepted me as an expert witness on energy matters.

I have conducted a wide range of professional activities during my career. I have spoken before the Commission, the U.S. Department of Justice, and the Federal Trade Commission. I have published articles in journals such as the *Antitrust Bulletin*, the *Journal of Regulatory Economics*, the *Electricity Journal*, and *Public Utilities Fortnightly*. Formerly I was the chairman of the Antitrust Committee of the Energy Bar Association.

I have previously taught economics at the University of Washington, Indiana University, and Stanford University (Washington, DC, campus). A complete listing of my experience, publications, and testimony is contained in my resume, presented in Exhibit JM-2.

On April 9, 2025, Florida Power & Light Company, Inc. ("FPL"), a subsidiary of NextEra Energy, Inc. ("NextEra"), entered into a purchase agreement to acquire the Vandolah Peaking Power Facility ("Vandolah") in Wauchula, Hardee County, Florida from Vandolah Power Company L.L.C. ("Vandolah Power") a subsidiary of Northern Star Generation LLC ("Northern Star"). Vandolah consists of four GE 7FA gas turbines with a total summer capacity of 660 MW based on ABB's Velocity Suite Generation Unit Capacity summer rating (and EIA Form 860 Summer Rating).[1] Vandolah is currently in the Duke Energy Florida ("DEF") Balancing Area Authority ("BAA"). FPL would, at time of close of the Transaction or shortly thereafter, energize a new transmission line to directly interconnect Vandolah with and move Vandolah into the

[1] All unit ratings for FPL in this filing are based on EIA-860 Summer ratings. The DPT also uses EIA winter ratings for FPL units. All other unit ratings are based upon seasonal ratings from Hitachi Energy, Velocity Suite, Generation Unit Capacity dataset.

FPL BAA. The parties expect to close on the Transaction on June 1, 2027.

FPL and Vandolah Power are filing for authority under Section 203 of the Federal Power Act to consummate the Transaction. In connection with that filing, counsel for FPL asked that I prepare a generation market power study to determine whether the Transaction would create or enhance market power in any relevant market.

2. Summary of Conclusions

Based upon the Competitive Analysis Screen (or Delivered Price Test ("DPT")), in conjunction with other market facts and circumstances previously relied on by the Commission, and the proposed mitigation, the proposed Transaction raises no competitive concerns. The Commission typically has considered Available Economic Capacity ("AEC") to be the more relevant metric for markets, like the BAAs in Florida, where there is no retail competition and little likelihood that retail competition will be adopted in the foreseeable future.[2] I also conducted an Economic Capacity ("EC") analysis, as required by the Commission.

I evaluate the impact of the Transaction by analyzing three scenarios, summarized in Table 1 and described in detail below. In the Base Case, the Vandolah facility is assumed to be under DEF's control during the pre-Transaction period.[3] For

2 See Duke Energy, 136 FERC ¶ 61,245 at P 124 (2011) ("the AEC measure is more appropriate for markets where there is no retail competition and no indication that retail competition will be implemented in the near future").

3 The Commission's regulations specify that capacity subject to a long-term agreement that confers control to the buyer is attributable to the buyer in the context of market power analyses. With respect to the determination of EC, the Revised Filing Requirements state: "Prior to applying the delivered price test, the generating capacity meeting this definition must be adjusted by subtracting capacity committed under long-term firm sales contracts and adding capacity acquired under long-term firm purchase contracts (i.e., contracts with a remaining commitment of more than one year). The capacity associated with any such adjustments must be attributed to

the post-Transaction period, I assume that a new transmission interconnection is constructed, FPL gains operational control of Vandolah, and the facility is incorporated into the FPL BAA as of the Transaction close.

Table 1: Scenarios Analyzed

	Pre-Transaction	Post-Transaction
Base Case	DEF controls Vandolah under long-term PPA.	FPL controls Vandolah and Vandolah moves to FPL BAA.
Alternate Case	DEF controls Vandolah under long-term PPA.	FPL controls Vandolah and Vandolah stays in DEF BAA.
But-for Case	DEF controls Vandolah under long-term PPA	DEF controls Vandolah and FPL builds new battery and gas turbine units.

In the Alternate Case, I retain the assumption that the Vandolah facility is under DEF's control during the pre-Transaction period. However, I assume the new transmission interconnection has not been completed by June 2027. As a result, FPL gains operational control of Vandolah at Transaction close but the facility remains within the DEF BAA for some period until the new line is energized.

In the But-for Case, I assume that Duke retains control of Vandolah, and FPL instead builds 400 MW of additional four-hour batteries and 475 MW of gas turbine units to meet its increasing demand.

2.1. Base Case Result Summary

Because most generation in the FPL BAA is owned by NextEra (via FPL), the transaction produces Herfindahl-Hirschman Index ("HHI") changes above the

the party that has authority to decide when generating resources are available for operation." 18 C.F.R. § 33.3(c)(4)(i)(A). This regulation also applies to the determination of AEC, as AEC is derived from EC "less the amount of generating capacity needed to serve the potential supplier's native load commitments." 18 C.F.R. § 33.3(c)(4)(i)(B). *See Osprey Energy Center, LLC*, 152 FERC ¶ 61,066 (2015) and *Shady Hills Power Company, L.L.C.*, 189 FERC ¶ 62,090 (2024)

Commission's screening thresholds.[4] The AEC results for FPL under the Base Case are shown in Table 2 below. The DPT analysis for the proposed Transaction identified two screen failures for the summer periods. Specifically, the analysis found that during the Summer Top 10% (S_T10) and Summer Top 1% (S_T1) periods, the change in the HHI exceeded the screening thresholds.

Table 2: Available Economic Capacity, Base Case, FPL

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,938	3,206	81.4	0	0.0	481	6,722
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,692	3,046	82.5	0	0.0	489	6,909
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

These screen failures should be interpreted in context. The FPL market is already highly concentrated prior to the Transaction. For example, for the Summer Top 10% period, the pre-transaction HHI exceeds 6,400. The approximately 584 MW of additional AEC supply resulting from the Transaction increases FPL's market share by 3.3 percentage points, from 79.2% to 82.5%, with a corresponding HHI increase of 489. Importantly, competitive supply—defined as AEC not affiliated with FPL from internal sources or imports—does not decline. In fact, in the FPL BAA, which is the most relevant destination market for this analysis, competitive supply remains the same during the periods in which the DPT screen fails. This outcome contrasts with typical acquisitions within a BAA, which usually result in a reduction in competitive supply. In other words, the DPT results indicate that wholesale buyers within the FPL BAA are not adversely affected; they have access to the same levels of competitive

[4] The screening thresholds are an increase of 50 or above when the post-transaction HHI is 1,800 or above and 100 or above when the post-transaction HHI is 1,000 or above and less than 1,800. Transactions clear the competitive analysis screen when the HHI changes are smaller or the post-transaction HHI levels are smaller.

supply post-Transaction. As further discussed in Section 6, these screen failures are best understood as false positives, as competitive supply is maintained—not diminished—following the Transaction. Accordingly, the DPT results do not reflect a diminution of competition.[5]

The AEC results for DEF under the Alternate Case are shown in Table 3 below. The DPT analysis shows that, for the DEF destination market, the DPT screens are passed for nine of ten periods. The one failure in the Spring/Fall Top 10% case is a false positive. Although NextEra's share increases because of Vandolah, supplies of others do not decrease. Moreover, the DPT does not account for the likely competitive response from DEF. Following the Transaction, DEF would likely develop new power generation resources to replace the loss of Vandolah to service its retail load obligations. As a result, the DPT results indicate that the Transaction raises no potential competition concern in the DEF destination market.

Table 3: Available Economic Capacity, Alternate Case, DEF

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	648	29.5	0	0.0	139	1,727
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

2.2. The Screen Violations Are Temporary Issues

Although Base Case DPT results contain some screen failures, a careful examination of these results demonstrates that they are not indicative of the presence of any long-term market power concern. Many other facts limit (or, indeed, eliminate) FPL's ability and/or incentive to exercise market power. In Order No. 642, the

5 See *Osprey Energy Center, LLC*, 152 FERC ¶ 61,066 at P 34 (2015).

Commission stated that it would look beyond the HHI screens if a transaction proposed under section 203 does not meet the HHI thresholds set forth in the Merger Policy Statement. The Commission clarified that applicants with screen failures could address market conditions beyond the change in HHI "such as demand and supply elasticity, ease of entry and market rules, as well as technical conditions, such as the types of generation involved."[6] In the Supplemental Policy Statement, the Commission stated that "in horizontal mergers, if an applicant fails the Competitive Analysis Screen (one piece of the Appendix A analysis), the Commission's analysis focuses on the merger's effect on the merged firm's ability and incentive to withhold output in order to drive up the market price."[7]

In the *Osprey* case, the Commission identified several factors that may indicate a transaction does not raise horizontal market power concerns, even when the DPT produces some screen failures. First, an increase in the HHI may overstate the transaction's competitive impact if the merging party's gain in market share is primarily due to the addition of new AEC, rather than the elimination of a competitor.[8] Second, the competitive effect of the proposed transaction may be similar to that of an alternative scenario—for example, where the merging party meets its future load obligations by building new supply rather than acquiring existing assets.[9] Third, regulatory factors may limit or eliminate the ability or incentive to exercise market power post-transaction.[10]

In this instance, as in the *Osprey* case, screen violations found in the DPT analysis are temporary issues and are not indicative of any actual long term potential

6 See, e.g., Duke Energy Corporation, 136 FERC ¶ 61,245 at P 126 (2011)

7 FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253 at P 60 (2007)

8 See *Osprey Energy Center, LLC*, 152 FERC ¶ 61,066 at P 34 (2015).

9 *Id.* at P 35.

10 *Id.* at P 36

competitive concerns.

2.2.1. The HHI Overstates the Transaction's Competitive Impact

To the extent that FPL's AEC and market concentration increase in the FPL BAA, these changes simply reflect the growth of FPL's generation fleet to meet the demand—not the elimination of a competitor—since the Vandolah facility is not located within the FPL BAA and is currently under contract to DEF. Moreover, the screen results would not be materially different if one assumed that, absent the Transaction, FPL constructs other energy sources comparable to the Vandolah facility, while Vandolah Power retains ownership and operation of Vandolah in the DEF BAA under a power purchase agreement with DEF. The key change here is the addition of AEC to FPL's portfolio, not a reduction in a competitor's AEC in FPL. As noted in the Direct Testimony of Andrew W. Whitley (the Whitley Testimony"), Integrated Resource Planning Manager at FPL, FPL's generation fleet is expected to grow regardless of whether the Transaction is completed to reliably serve its increasing load and meet reserve margin requirements. The increase in FPL's AEC would happen regardless of the Transaction. In Sections 2.3 and 6.2, I present DPT results under a "But-for Case" where FPL constructs alternative sources comparable to the Vandolah facility and Vandolah is in the DEF BAA under a power purchase agreement with DEF.

2.2.2. FPL plans to Build Additional Supply to Meet Its Load Obligation

The proposed Transaction is being pursued by FPL in response to FPL's need to address significant capacity shortfalls arising from future load growth. As explained by Mr. Whitley, FPL has conservatively forecasted a "short" position of more than

1,780 MW of portfolio capacity relative to its total reliability need by 2030.[11] That shortfall is forecast to grow, by 2035, to 5,592 MW if FPL does not add additional capacity resources to its system.

According to FPL's 10-Year Power Plant Site Plan shown in Table 4 below, the company anticipates substantial solar and battery storage additions in the But-for Case between 2028 and 2033. This includes planned solar additions of 1,490 MW in 2028, 1,788 MW in 2029, and 2,235 MW in both 2030 and 2031, as well as annual battery storage additions of 596 MW from 2028 through 2031. As discussed in more detail in the Whitley Testimony, FPL performed a Cumulative Present Value Revenue Requirements ("CPVRR") analysis of different options that demonstrates that the Vandolah facility presents an attractive alternative, and will in fact displace (i) 400 MW of 4-hour batteries that would otherwise have entered service by January 1, 2028 and (ii) 475 MW of new combustion turbines that would otherwise have entered service by January 1, 2032. Acquiring Vandolah rather than building these resources offers long-term CPVRR savings for FPL's customers. The savings are driven in large part by the fact that, on a per-MW basis, Vandolah is more cost-effective than new-build gas-fired generation.[12]

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11 See Whitley Testimony, Docket No. EC25-__-000, June 9, 2025, at p. 15

12 Whitley Testimony, Docket No. EC25-__-000, June 9, 2025.

Table 4: FPL's Current 10 Year Power Plant Site Plan

Year	Change to Existing Generation (MW)	Subtractions (MW)	New Solar Generation Additions (MW)	New Battery Storage Additions (MW)	New Gas Thermal Additions (MW)
2027	48 MW CC Upgrades	Broward South (4 MW)	1,192	819.5	
2028	14 MW CC Upgrades	Lansing Smith 3A (32 MW)	1,490	596	
2029		GCEC 4 (75 MW) GCEC 5 (75 MW)	1,788	596	
2030		Perdido 1&2 (3 MW)	2,235	596	
2031			2,235	596	
2032		Palm Beach SWA 1 (40 MW)	2,235		2x0 Manatee CT (475 MW)
2033			2,235	1,192	
2034			2,235	1,267	
Total	62	(220)	15,645	5,662.5	475

Source: Florida Power & Light, Ten Year Power Plant Site Plan 2025-2034.

2.2.3. Regulatory Factors Reduce or Eliminate Any Anticompetition Concern

In addition, several regulatory factors—both individually and collectively—substantially reduce, if not eliminate, any theoretical ability or incentive FPL might have to withhold available EC following the Transaction.

First, both federal and state regulations significantly constrain any potential to raise market prices. FPL lacks authority to make wholesale sales at market-based rates within the FPL, Homestead, Florida Municipal Power Pool ("FMPP"), and Gainesville ("GVL") BAAs. Instead, wholesale and retail sales in these regions must be conducted at cost-based rates regulated by FERC or the Florida Public Service Commission ("Florida PSC"), respectively.

Second, FPL's long-term full and partial requirements wholesale customers in Florida are protected from unilateral price increases by the terms of their existing contracts, or by commitments offered by FPL in this application. Any changes to capacity rates under these agreements would require FERC approval. Moreover, even if FPL were to seek recovery of Vandolah-related costs through these contracts, customers would benefit from the facility's lower cost compared to new-build alternatives.

Taken together, these factors demonstrate that, despite the screen failures, any ability or incentive for FPL to withhold generation and profitably raise market prices on a sustained basis is likely to be limited or temporary at best.

2.3. HHI Impact of the Transaction Comparable to FPL Building New Generation

In this section, I assess the impact of the Transaction by evaluating the likely alternative scenario if the proposed Transaction does not proceed, which I call the "But-for Case". In this scenario, I assume that FPL would install 400 MW of four-hour battery storage systems and 475 MW of combustion turbines—capacity additions that, according to Mr. Whitley, FPL will avoid through the Vandolah acquisition. I also assume that Vandolah Power retains ownership and operation of the Vandolah facility, which remains located in the DEF BAA and operates under a power purchase agreement with DEF. Under this scenario, the planned transmission upgrades associated with the Transaction are not developed, and the Vandolah facility continues to be electrically located within the DEF BAA.

Table 5 presents the AEC results for the But-for Case. The DPT analysis identifies a greater number of screen failures under the But-for Case compared to the Base Case. Specifically, screen failures are observed in seven periods: Spring/Fall Off Peak (SF_OP), Spring/Fall Top 10% (SF_T10), Summer Peak (SUM_P), Summer Top 10% (SUM_T10), Summer Top 1% (SUM_T1), Winter Off Peak (WIN_OP), and Winter Top 10% (WIN_T10). These results suggest that the Vandolah acquisition results in changes in market concentration that are similar to (or in fact less) than those that would be observed in the scenario in which the Transaction does not occur.

Table 5: Available Economic Capacity, But-for Case, FPL

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,735	2,451	65.6	0	0.0	434	4,643
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,560	6,967	92.2	0	0.0	0	8,502
SF_OP	34.12	6,666	5,595	83.9	0	0.0	7,062	5,991	84.8	0	0.0	145	7,252
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	4,179	3,447	82.5	0	0.0	646	6,887
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,868	3,222	83.3	0	0.0	613	7,033
SUM_P	44.35	5,773	5,131	88.9	0	0.0	6,381	5,740	90.0	0	0.0	182	8,125
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,330	4,031	93.1	0	0.0	21	8,695
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	9,551	8,144	85.3	0	0.0	109	7,316
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,503	9,576	91.2	0	0.0	0	8,324
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	11,271	9,737	86.4	0	0.0	87	7,493

2.4. Proposed Temporary Mitigation Solves Screen Violation in FPL for the Base Case

In the Base Case, a new transmission interconnection is constructed, FPL gains operational control of Vandolah, and the facility is incorporated into the FPL BAA as of the Transaction close.

Should the Commission determine that the limited screen failures in the Base Case analysis require mitigation, FPL has developed a mitigation proposal intended to eliminate any potential concerns regarding the potential exercise of market power. The mitigation proposal necessarily takes into consideration the limitations that (i) FPL must acquire additional generation to meet its state retail load and reserve obligations; and (ii) FPL lacks market-based rate authority so must sell at approved cost-based rates within the region.

We model the temporary mitigation, whereby FPL has committed to a day-ahead must-offer of two Vandolah units, by assuming that FPL would not control two out of the four units at the Vandolah facility after the Transaction and that capacity is available to the market. As shown in Table 6 below, the proposed mitigation completely cures the identified screen failures in the Summer Top 10% (S_T10) and Summer Top 1% (S_T1) periods. Moreover, the available supplies to the market increase. In addition, mitigation also cures screen failures in summer off peak and shoulder season when prices are elevated +10%.

Table 6: Available Economic Capacity, Base Case, FPL (With Mitigation)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,937	2,915	74.0	0	0.0	-611	5,630
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,690	2,754	74.6	0	0.0	-685	5,736
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

2.5. Proposed Temporary Mitigation in the Alternate Case

In the Alternate Case, a new transmission connection is not built by the time the Transaction closes. FPL gains operational control of Vandolah, and the facility stays in the DEF BAA. FPL would commit, for any period of time (i) following closing; and (ii) before energization of the new line, to offer behavioral mitigation in the form of a "must offer" for at least 330 MW of Vandolah output in the DEF BAA. FPL would transition to the previously discussed Base Case temporary mitigation once the transmission line energizes, and Vandolah moves to the FPL BAA.

There was one screen failure in the DEF BAA destination under the Alternate Case, during the Spring/Fall Top 10% (SF_T10), and FPL proposes temporary mitigation during shoulder season peak hours for as long as Vandolah is owned FPL and remains in the DEF BAA. Accordingly, I model temporary mitigation in this scenario by assuming that FPL relinquishes control of two of the four units at the Vandolah facility through a must-offer commitment following the Transaction. Table 7 below presents the DPT test results for the DEF destination market. As expected, there are no screen failures in any periods. Additional DPT results for the price sensitivities cases and first-tier markets are shown in Exhibit No. JM-12.

Table 7: Available Economic Capacity, Alternate Case, DEF (With Alternate Case Mitigation)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	363	16.5	0	0.0	-291	1,298
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	297	14.6	0	0.0	-692	1,550
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	297	14.7	0	0.0	-694	1,553
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

The DPT test results are confirmed with historical production and sales data for FPL. See Section 8, below. Therefore, the Transaction presents no loss of competition after the proposed mitigation measures. Finally, the Transaction will not adversely affect capacity and ancillary service markets and does not raise any vertical market power concerns.

In summary, FPL's acquisition of Vandolah provides no risk of anticompetitive effects with the proposed mitigation measures. Accordingly, I recommend that the Commission conclude that the Transaction passes the effect on competition prong of the Commission's public interest review of applications under Section 203 of the Federal Power Act.

3. Description of FPL, NextEra, and their Generation Assets

3.1. NextEra and FPL

NextEra is a leading clean energy company headquartered in Juno Beach, Florida.[13] NextEra owns a competitive clean energy business, NextEra Energy Resources, LLC ("NEER"), which, together with its affiliated entities, is the world's largest generator of renewable energy from the wind and sun and a world leader in

[13] See https://www.investor.nexteraenergy.com/company-overview

battery storage. Through its subsidiaries, NextEra generates clean, emissions-free electricity from seven commercial nuclear power units in Florida, New Hampshire and Wisconsin.

NextEra owns FPL which provides clean, affordable, reliable electricity to approximately 6 million customer accounts, or more than 12 million people across Florida. FPL is a vertically integrated electric utility and owns or controls around 33,300 MW of generating capacity.[14] Exhibit JM-3 provides a list of generation assets that are owned or controlled by NextEra in FPL and areas first-tier to FPL. The sources for these data are NextEra's Asset Appendix (Serial Number 27755 filed with FERC on May 29, 2025); EIA-Form 860M (April 2025); Hitachi Energy, Velocity Suite, Generation Unit Capacity dataset; and FPL's 10-year site plan. All capacity operating as of January 1, 2025, has capacity ratings from EIA-861. Newer generation not yet in EIA-861 have capacity ratings from Hitachi Energy or FPL's 10-year site plan. Generation capacity not yet online are indicated by the expected online year. Contract data come from FPL's FERC-filed Asset Appendix.

3.2. Northern Star, Vandolah, and Duke Energy Florida

Northern Star is a privately held power generation company dedicated to providing reliable service to its customers, most of whom hold long-term contracts with Northern Star for power generation capacity and energy production.[15] Northern Star was formed in early 2004 to own and operate a portfolio of power plants with long-term contracts that was divested by El Paso Corporation. Since the initial acquisition from El Paso in 2004, Northern Star has completed several transactions to add to its ownership share of these plants.

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14 Some of the generation in the Exhibit JM-3 is owned by NEER, hence the total owned generation for the FPL BAA is greater than 33,300 MW. Most generation owned by NEER can be identified because those units are matched with contracts to third parties.

15 *See* https://northernstargeneration.com/index.html.

Vandolah Power is indirectly owned by Northern Star Generation LLC. Vandolah is a 660 MW (Summer) dual fuel, peaking plant, and it is an Exempt Wholesale Generator that began commercial operations in June 2002. Through May 31, 2027 the plant is fully contracted under a tolling agreement with Duke Energy Florida. Vandolah has four GE 7FA gas CTs with a combined 660 MW summer rating. Vandolah's capacity factor was 13% in 2023 and 2024.[16]

Duke Energy, a Fortune 150 company headquartered in Charlotte, N.C., is one of America's largest energy holding companies.[17] The company's electric utilities serve 8.6 million customers in North Carolina, South Carolina, Florida, Indiana, Ohio and Kentucky, and collectively own approximately 55,100 megawatts of generation capacity.[18] DEF entered into a tolling agreement (the power purchase agreement or "PPA") with Vandolah Power beginning June 1, 2012, for the entire output of the Vandolah Facility. DEF has assumed responsibility for providing transmission for final delivery to DEF native load. Exhibit JM-3 provides a list of generation assets that are owned or controlled by Duke Energy in FPL and areas first-tier to FPL. The sources and methodology are the same as for the FPL capacity in Exhibit JM-3 with addition of Duke's Asset Appendix.

4. Methodology to Review Competitive Effects of the Acquisition

The report considers whether the proposed acquisition of the Vandolah facility by FPL will result in FPL obtaining or increasing market power following the Transaction. Market power is the ability of a seller or group of sellers to profit from restricting output and maintaining prices "above competitive levels for a significant

16 Hitachi Energy, Inc., Velocity Suite, Unit Generation & Emissions – Annual database.

17 *See* https://www.duke-energy.com/our-company/about-us.

18 *Id.*

period."[19] Therefore, the central competitive issue is whether the acquisition will give FPL the incentive and the ability to withhold output and raise wholesale electricity market prices.[20] To examine this issue, the report uses standard market power analysis methods used by the Commission and economists.

4.1. Foundation of the Screening Method

The analytical framework for this report was established by the 1992 Horizontal Merger Guidelines issued by the Department of Justice and Federal Trade Commission (Agency) and adopted by the Commission in its *Merger Policy Statement*.[21] The antitrust agencies revised the 1992 Merger Guidelines in 2010, adding some concepts and clarifications, but the core of the 1992 framework was retained.[22] This framework includes a five-step procedure for analyzing mergers and

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19 U.S. Department of Justice and Federal Trade Commission. *Horizontal Merger Guidelines*. issued April 2, 1992, 57 FR 41,552, Section 0.1 (1992), *available at* http://www.justice.gov/atr/hmerger/11250.htm.

20 FPA Section 203 Supplemental Policy Statement, FERC Stats. & Regs. ¶ 31,253, at P 60 (2007) ("Supplemental Policy Statement"), order on clarification and reconsideration, 122 FERC ¶ 61,157 (2008) ("Clarification Order") ("Commission's analysis focuses on the merger's effect on the merged firm's *ability* and *incentive* to withhold output in order to drive up the market price.").

21 *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶31,044 (1996) ("*Merger Policy Statement*"), reconsideration denied, Order No. 592-A, 79 FERC ¶ 61,321 (1997). The Agency subsequently adopted revised guidelines in 2010. *See* U.S. Department of Justice and the Federal Trade Commission, Horizontal Merger Guidelines (issued Aug. 19, 2010) ("2010 Merger Guidelines"), *available at* http://ftc.gov/os/2010/08/100819hmg.pdf. The Commission expressly declined to adopt the HHI screening thresholds of the 2010 Merger Guidelines, instead reaffirming its reliance on the 1992 Merger Guidelines screening thresholds. *See Analysis of Horizontal Market Power under the Federal Power Act*, 138 FERC ¶ 61,109 at P 2 (2012) ("*Analysis of Horizontal Market Power*").

22 The Merger Guidelines were revised again in 2023. *See* U.S. Department of Justice & Federal Trade Commission, Merger Guidelines (2023), available at https://www.ftc.gov/system/files/ftc_gov/pdf/2023_merger_guidelines_final_12.18.2023.pdf This latest revision is drafted more as a reference from prior antitrust decisions less of the economic framework of the 1992 and 2010 Horizontal Merger Guidelines. The Commission has considered any changes to its analytic framework since the 2023 Merger Guidelines.

acquisitions of generation assets by another entity.[23]

The first step in the analysis is to identify the relevant destination market and products and assess whether the merger (or acquisition) can significantly increase concentration and result in a concentrated market. The second step is to evaluate whether the merger or acquisition, in light of market concentration and other factors that characterize the market, raises concern about potential adverse competitive effects.[24] The third step is to assess other factors to determine whether the screens provide a "false positive" suggesting that market power may exist when, in fact, it does not.[25] The fourth step requires an assessment of whether there are any efficiency gains that reasonably cannot be achieved through means other than the transaction. The fifth step is to check if either party to the transaction would likely fail, causing its assets to exit the market if the merger or acquisition does not take place. The analysis in this report involves all these steps.

The Commission in Order Nos. 592 and 642 articulated specific methods of defining markets and measuring market concentration.[26] These methods are commonly referred to as the delivered price test, or DPT. The Commission uses the market concentration thresholds of the *1992 Merger Guidelines* to establish whether

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23 *See Merger Policy Statement*; Order No. 642 at 31,882.

24 *Id.* at 31,886 ("the competitive analysis screen is intended to provide a standard, generally conservative check to allow the quick identification of mergers that are unlikely to present competitive problems, and is not meant to be a definitive test of the competitive effects of a proposed merger.")

25 *Supplemental Policy Statement* at P 65 ("… [T]he Commission does look beyond the change in HHI in its analysis of the effect on competition in both horizontal and vertical mergers. The change in HHI serves as a screen to identify those transactions that could potentially harm competition. If the screen is failed, then … the Commission examines the factors that could affect competition in the relevant market. Specifically, in these circumstances the Commission typically considers a case-specific theory of competitive harm, which includes, but is not limited to, an analysis of the merged firm's ability and incentive to withhold output in order to drive up prices.").

26 *See* Order No. 642 at 31,873.

additional analysis is necessary to determine the competitive effects or mitigation is necessary to alleviate concerns of potential anticompetitive effects.

Per instructions in Order No. 642 and standard economic practice, the report uses the HHI measure of market concentration.[27] The HHI is calculated as the sum of the squares of each company's market shares. Hence, a market with four companies having market shares of 40, 30, 20, and 10 percent would have an HHI of 3,000 ($3{,}000 = 40^2 + 30^2 + 20^2 + 10^2 = 1{,}600 + 900 + 400 + 100$). Under the *1992 Merger Guidelines*, markets with an HHI of less than 1,000 are unconcentrated and ordinarily require no further analysis because any mergers or acquisitions are unlikely to have adverse competitive effects. A market is moderately concentrated when the post-merger HHI is between 1,000 and 1,800. Mergers or asset acquisitions that result in an increase in the HHI of less than 100 points in moderately concentrated markets are unlikely to have adverse competitive consequences and ordinarily require no further analysis. Markets with a post-transaction HHI over 1,800 are highly concentrated. Even in highly concentrated markets, if the merger or asset transaction produces an increase in the HHI of less than 50 points, the transaction is unlikely to have adverse competitive consequences and ordinarily requires no further analysis. These market concentration levels and changes establish a "safe harbor" where the Commission may reasonably conclude, absent additional information, that a merger or asset acquisition is unlikely to result in anticompetitive effects.[28] When a transaction produces HHI increases above the safe harbor thresholds, then the

[27] *Id.* at 31,896.

[28] *See Merger Policy Statement* at 30,119 ("The Commission believes that the screen will be a valuable analytical tool in all cases. It is conservative enough so that parties and the Commission can be confident that an application that clears the screen would have no adverse effect on competition.") Under the 2010 Merger Guidelines, the federal antitrust agencies now employ higher thresholds. *See Analysis of Horizontal Market Power* at P 8 (comparing the thresholds under the 1992 and 2010 Merger Guidelines). As noted above, the Commission has not adopted the 2010 Merger Guidelines (*Id.* at P 35), and, therefore, the lower screening thresholds set forth in the 1992 Merger Guidelines were used in this analysis.

Commission examines competitive effects, efficiencies, and the likelihood of market exit.[29]

4.2. Product Markets

As articulated in Order Nos. 592 and 642, the relevant products for competition analysis typically include the short-term energy, capacity and ancillary services markets.[30] The short-term energy market is discussed in Section 5 through Section 7. The transaction will not adversely affect capacity or ancillary service markets. The report does not consider competition in long-term capacity or energy contracts. The Commission has correctly concluded that long-term generation markets are competitive and generation market power analysis should focus on short-term markets.[31]

4.3. Destination Markets

The relevant destination markets are the areas in which the two entities compete for customers.[32] Exhibit JM-4 shows sales data by NextEra and Duke Energy. FPL plans to build a transmission line to directly connect its BAA to Vandolah post-Transaction. Therefore, the DEF and FPL BAAs and BAAs first-tier to them are the relevant destination markets for considering the effects of the acquisition.

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29 Order No. 642 at 31,911 ("… the factors that applicants would have to evaluate in this stage of the analytic framework are those set out in Sections 2 through 5 of the Guidelines: potential adverse competitive effects, … merger-related efficiencies, and whether one of the merging firm's assets would exit the market but for the merger.")

30 Order No. 642 at 31,882.

31 *See* Order No. 697 at P 122 ("As the Commission has stated in the past, absent entry barriers, long-term capacity markets are inherently competitive because new market entrants can build alternative generating supply."); *Kansas City Power & Light*, 67 FERC ¶ 61,183, at 61,557 (1994).

32 *See*, Order No. 642 at 31,884-31,885; 18 C.F.R. § 33.3(a)(2) ("A horizontal Competitive Analysis Screen need not be filed if the applicant: (i) Affirmatively demonstrates that the merging entities do not currently conduct business in the same geographic markets…").

5. Data Sources and Methodology for the Delivered Price Test

This section provides an overview of the sources and methods used for the DPT. A more detailed description of data sources and methods to prepare the data for the DPT is presented in Exhibit JM-5.

The DPT calculates shares and the HHI for EC and AEC. EC is the amount of the relevant product (short-term energy) that suppliers could economically physically sell to each of the potential destination markets at no more than 105 percent of the expected market price. AEC is EC less retail and wholesale load commitments.

This report uses 10 representative market conditions defining categories of peak and off-peak load hours across three defined seasonal periods: Spring/Fall, Summer, and Winter.[33]

SPRING/FALL (Shoulder) (March-April-May-September-October-November)

SF_T10:	Top 10% of peak load hours
SF_P:	Remaining peak hours
SF_OP:	All off-peak hours

SUMMER (June-July-August)

SUM_T1:	Top 1% of peak hours
SUM_T10:	Top 10% of peak load hours
SUM_P:	Remaining peak hours
SUM_OP:	All off-peak hours

WINTER (December-January-February)

WIN_T10:	Top 10% of peak load hours
WIN_P:	Remaining peak hours
WIN_OP:	All off-peak hours

33 *See AEP Power Marketing*, 107 FERC ¶ 61,018 at App. F ("… analyze: Super-Peak, Peak, and Off-Peak, for winter, shoulder and summer periods, and an extreme Summer Peak, for a total of ten season/load levels"). To be more specific, I use "Top 10%" for Super-Peak, "Top 1%" for extreme Summer Peak, and "spring/fall" for shoulder.

Average load levels and median prices for these periods are based on two years of historical data, from January 2023 through December 2024, the most recent data available for the destination markets and first-tier areas.[34] This period is the base period for data, and load levels, historical market prices, and fuel costs are calculated based on data during this period.[35]

Because merger analysis is forward looking,[36] it is necessary to convert the historical load, fuel cost, and electric market price data to the forward-looking study period. The historical load levels are "moved" from the base period to the future study period of June 2027 through May 2028 based on load forecasts in the 2024 FERC Form 714. Fuel costs are moved from the base period to the study period by adding changes in forward prices to the actual historical fuel costs. Electric power market prices are moved from the base period to the study period via a price simulation for the base period and the study period.[37] The changes in prices in the simulation are then added to the historical median prices during the base period.[38] The simulation accounts for changes in load levels, the generation fleet, and fuel costs between the historical and the study period. Because some BAAs in Florida are thinly traded, I

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34 *See* 18 C.F.R. § 33.3(d)(4)(ii) ("The applicant must provide supplier name and hourly native load commitments for the most recent two years.").

35 *See* 18 C.F.R. § 33.3(d)(6) ("The applicant must provide, for each relevant product and destination market, market prices for the most recent two years. The applicant may provide suitable proxies for market prices if actual market prices are unavailable.").

36 *See* Order No. 642 at 31,887 ("…the competitive analysis screen is intended to be a forward-looking measure.").

37 *See* 18 C.F.R. § 33.3(b)(3) ("The applicant may use a computer model to complete one or more steps in the horizontal Competitive Analysis Screen.")

38 The use of median historical prices (instead of average) are often more representative of "typical" market prices. *See* John Morris, Jéssica Dutra, and Tristan Snow Cobb, *Alternative Measures of "Representative Market Prices" for FERC Delivered Price Tests*, 42 ENERGY L.J. 191 (2021). The Commission has accepted this methodology on previous occasions. *See, for example*, Report and Affidavit of Dr. John R. Morris, NRG Energy, Inc., FERC Docket No. EC20-96-000 (2020); Report and Affidavit of Dr. John R. Morris, Entergy Texas, Inc., FERC Docket No. EC20-85-000 (2020).

require that the representative price for a destination be in the range from (1) the FPL representative price less transportation costs to FPL to (2) the FPL representative price plus transportation to the destination BAA. As the Commission has requested, I also undertook sensitivity studies varying market prices +/- 10 percent.[39]

Both EC and AEC are used as measures of energy in conducting the DPT to assess horizontal market power. Under both measures, the capacity that is attributed to a market participant is that capacity controlled by it that can reach the destination market, taking transmission constraints and costs into account, at a price no higher than 105 percent of the destination market price.[40] The Commission in recent years has given more weight to the results of AEC analyses in non-restructured markets (*i.e.*, where traditional suppliers maintain load-serving responsibility).[41] Florida has not restructured its electric power market; accordingly, AEC is the measure to assess potential competitive effects.

The primary source for generation data is the Velocity Suite Generation Unit Capacity database vended by Hitachi Energy, Inc.[42] Velocity Suite provides data by generation unit including capability, ownership, heat rates, fuel costs, emission rates,

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39 *Id.* at § 33.3(d)(6) ("Applicants must demonstrate that the results of the analysis do not vary significantly in response to small variations in actual and/or estimated prices.").

40 *See* 18 C.F.R. § 33.3(c)(4).

41 *See*, *e.g.*, *Nevada Power Co.*, 113 FERC ¶ 61,265 at P 15 (2005) (finding that AEC is a more accurate measure for markets where utilities have significant native load obligations); *Kansas City Power & Light Co.*, 113 FERC ¶ 61,704 at PP 31, 35 (2005) ("[U]tilities with a native load obligation are obligated to secure and devote resources to serve that native load. Depending on load conditions, some or all of those resources are not available to the wholesale market and the available economic capacity measure accounts for that."). *Cf. Market-Based Rates for Wholesale Sales of Elec. Energy, Capacity and Ancillary Servs. by Pub. Utils.*, Order No. 697, 119 FERC ¶ 61,295 at P 112 (2007) ("Order No. 697") (stating that, "in markets where the sellers have been predominately relieved of their native load obligations, an analysis of economic capacity may more accurately reflect market conditions and a seller's relative size in the market").

42 Velocity Suite contains many databases containing energy market data ranging from details on generation units to historical weather information.

and generation availability. For NextEra, Duke, and Vandolah generation capacity, I use EIA-860M data. Unit capabilities are adjusted to account for seasonal maintenance and expected plant unavailability due to forced outages. I also accounted for the change in operational control of contracted units in the HHI calculations. Data on transmission rates and losses come from the utility tariffs.

The EC, AEC, share, and HHI calculations are performed using the Power Acquisition Screening System ("PASS"). The system consists of proprietary software to maintain the relevant data and perform the calculations. It consists of a database interface in Microsoft Access to handle the data and a linear programming model to calculate EC and AEC, to allocate transmission, to calculate shares, and to calculate HHIs. Per directions from the Commission, all the input data, intermediate data, and results are provided in Excel (or CSV) spreadsheet format to assist in the review of the methodology and results.[43] Transmission to each destination market is allocated pro rata per the guidance given by the Commission in Order 697.[44] The mathematical details are presented in Exhibit JM-6. The calculation of Simultaneous Import Limits ("SILs") is described in Exhibit JM-7.

6. Quantitative Results Indicate the Transaction Will Not Create or Enhance Market Power with the Proposed Mitigation Measure

In this section, I present the analytical results for the analyses described in Section 5. First, I analyze the Base Case, in which FPL energizes a new transmission line at the time of the Transaction's closing, directly interconnecting the Vandolah facility with the FPL BAA. As a result, Vandolah shifts from the DEF BAA to the FPL BAA. I present the DPT results for the FPL destination market, followed by an evaluation of the proposed mitigation measure. Second, I evaluate the But-for Case,

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43 *Merger Policy Statement* at 30,120 ("Applicants should file in electronic format the data specified as well as any other data used in their analysis.")

44 Order No. 697 at P 374-375.

where FPL constructs additional new batteries in line with its 10-year plan, and the Vandolah facility continues operating under a PPA with DEF, remaining in the DEF BAA. Third, I assess an Alternate Case in which FPL does not complete the new transmission line prior to the Transaction's closing, and Vandolah remains in the DEF BAA. I analyze the DPT results in the DEF destination market and assess the impact of the proposed mitigation measure.

6.1. DPT Results for Vandolah in FPL

6.1.1. DPT Results for Base Case

The AEC results for FPL in the Base Case are shown here in Table 8 (which is the same as Table 2 in the summary). Additional DPT results for the Base Case are provided in Exhibit JM-8. These include the results of sensitivity tests around market prices in FPL, the AEC results for first-tier destination markets and the EC results.

As discussed earlier in section 2, there are screen failures in the Summer Top 10% (SUM_T10) and Summer Top 1% (SUM_T1) periods. Also of note, the results show the effects of not having 400 MW of batteries that would have been online by 2028 but for the acquisition of Vandolah. Not constructing the batteries has the effect of decreasing the HHI levels in periods when Vandolah is not economic. The batteries are not expected to have been operating by the summer of 2027, so they do not affect the summer results presented here.

Table 8: Summary Results for AEC in FPL, Base Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,938	3,206	81.4	0	0.0	481	6,722
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,692	3,046	82.5	0	0.0	489	6,909
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

Table 9 summarizes the AEC results for the plus 10% price sensitivity in the FPL destination market for the Base Case. Screen failures occur during the Spring/Fall Top 10% (SF_T10), Spring/Fall Peak (SF_P), Spring/Fall Off Peak (SP_OP), Summer Off Peak (SUM_OP), Summer Peak (SUM_P), Summer Top 10% (SUM_T10), and Summer Top 1% (SUM_T1) periods.

Table 9: Summary Results for AEC in FPL, +10% Prices, Base Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,945	3,306	66.8	0	0.0	267	4,758
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,686	8,305	85.7	0	0.0	57	7,417
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,970	6,656	83.5	0	0.0	172	7,023
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	3,938	3,206	81.4	0	0.0	481	6,722
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,692	3,046	82.5	0	0.0	489	6,909
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,726	6,084	90.5	0	0.0	157	8,215
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,676	6,204	92.9	0	0.0	122	8,653
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	9,317	7,745	83.1	0	0.0	-77	6,964
WIN_P	42.83	12,693	11,138	87.8	0	0.0	12,501	10,946	87.6	0	0.0	-32	7,694
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,207	10,668	87.4	91	0.7	-14	7,657

In addition, as shown in Table 10, screen failures also occur in the Summer Top 1% periods under the minus 10% price sensitivity.

Table 10: Summary Results for AEC in FPL, -10% Prices, Base Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	895	270	30.2	0	0.0	-890	1,675
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,191	5,631	91.0	0	0.0	-49	8,288
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,236	5,731	91.9	0	0.0	-18	8,461
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	3,805	3,086	81.1	0	0.0	504	6,677
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	1,792	1,310	73.1	0	0.0	0	5,584
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,198	2,894	90.5	0	0.0	0	8,242
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,020	5,258	87.3	0	0.0	-12	7,666
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,166	9,388	92.3	0	0.0	-26	8,537
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	9,984	9,268	92.8	0	0.0	-10	8,626

However, as shown in Table 11 below, for each period in which the HHI screens indicate a failure under base prices, competitive supply—defined as AEC not affiliated with FPL, whether from internal sources or imports—does not decline. In fact, competitive supply in the FPL BAA remains unchanged in all but the Summer Peak period when the competitive supply falls by only 1 MW and the HHI is below screening thresholds. Although the Transaction may result in FPL holding a larger share of AEC in the FPL BAA, this increase reflects an increase in overall supply, which is generally considered procompetitive rather than anticompetitive. From this standpoint, the screen failures should not be interpreted as evidence of increased market power by FPL.

Table 11: AEC Competitive Supply Analysis, FPL, Base Case

Period	Price ($/MWh)	Screen Failure	Change in Market Size (MW)	Change in FPL's AEC (MW)	Change in DEF's AEC (MW)	Change in Competitive Supply (MW)	False Positive
SF_T10	43.88	No	-260	-260	0	0	N/A
SF_P	37.63	No	-192	-192	0	0	N/A
SF_OP	34.12	No	-76	-76	0	0	N/A
SUM_T1	60.20	Yes	584	584	0	0	Yes
SUM_T10	48.08	Yes	584	584	0	0	Yes
SUM_P	44.35	No	146	147	0	-1	N/A
SUM_OP	38.09	No	0	0	0	0	N/A
WIN_T10	40.13	No	-189	-189	0	0	N/A
WIN_P	38.94	No	-192	-192	0	0	N/A
WIN_OP	37.51	No	-80	-80	0	0	N/A

First-Tier Markets. Exhibit JM-8 contains the AEC results for all first-tier destinations. No screen failures occur in the Seminole Electric Cooperative ("SEC"), Southern Company ("SOCO"), or Tampa Electric Company ("TEC") BAAs. Screen failures occur in the DEF, FMPP, GVL, Jacksonville ("JEA"), and Tallahassee ("TAL") BAAs. Virtually all of these are false positives falling into two categories. First, some, like in the DEF BAA, occur even though the supplies of others increase because the SIL increases when Vandolah moves to the FPL BAA. This increases FPL share of the pro-rata allocation of transmission, but it also means more energy of others can reach the destination. These are false positives because the supplies of others are not diminished. Second, some screen violations occur when the SIL decreases but the FPL capacity and energy decreases and the share of the only potential customer is that share that increases. For example, the DPT shows screen failures in the TAL BAA during the Winter and Spring/Fall seasons. The results are driven by a lower SIL when Vandolah is moved to FPL, and TAL's large share in its own area increases. But TAL is the only wholesale customer in its area. Because (1) TAL already has enough resources to serve its load and (2) TAL would not raise prices to itself, the results for TAL are properly considered as false positives. Therefore, the results in other BAAs do not indicate the potential for FPL to raise prices anticompetitively from the Transaction.

Economic Capacity. The results for EC are included in Exhibit JM-8. As expected, there are screen failures in some markets, but because there is no retail competition in Florida, EC results are neither informative nor reliable in assessing the market power effect of the Transaction.

Overall, the DPT results suggest that, under the Base Case, the proposed Transaction does not raise major competitive concerns in any BAAs other than FPL BAA.

6.1.2. DPT Results for Base Case with the Proposed Mitigation Measure

We model the temporary mitigation for the base case by assuming that FPL gives up control of two of the four units at the Vandolah facility after the Transaction via a must offer obligation. Table 12 (which is the same as Table 6 in the summary) presents summary results for AEC with the proposed mitigation measure for FPL destination market. Additional DPT results for the Base Case with mitigation are provided in Exhibit JM-9. These include sensitivity analyses around market prices in the FPL BAA, AEC results for first-tier markets, and EC results. The DPT results show that the proposed mitigation measure completely cures the screen failure in FPL in all periods for both the base price and plus and minus 10% price sensitivity.

Table 12: Summary Results for AEC with Mitigation Measure in FPL, Base Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,937	2,915	74.0	0	0.0	-611	5,630
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,690	2,754	74.6	0	0.0	-685	5,736
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.50	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

The proposed mitigation does not remedy the screen failures observed in DEF, GVL, JEA, FMPP and TAL. However, as explained above, in these thinly traded markets, the DPT may produce misleading results. Because the transaction does not result in a reduction in competition in these markets, there is no competitive concern even in the absence of mitigation measures.

For the reasons discussed above, I conclude that the Transaction, even absent mitigation, does not raise horizontal market power concerns. Nonetheless, the proposed mitigation provides an additional safeguard to further ensure that no competitive concerns arise.

6.2. DPT Results for But-for Case

Table 13 (identical to Table 5 in the summary) presents summary results for AEC for the FPL BAA destination market in the But-for Case. Additional DPT results for the But-for Case are provided in Exhibit JM-10. These include sensitivity analysis around market prices in the FPL BAA, AEC results for first-tier markets, and EC results. Under the But-for Case, screen failures occur in seven periods: Spring/Fall Off Peak, Spring/Fall Top 10%, Winter Off Peak, Winter Top 10%, Summer Peak, Summer Top 10%, and Summer Top 1%. Compared to the Base Case, the DPT fails in more periods under the But-for Case. Additionally, isolated screen failures are observed in two first-tier markets, GVL and JEA.

Table 13: Summary Results for AEC in the FPL BAA, But-for Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,735	2,451	65.6	0	0.0	434	4,643
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,560	6,967	92.2	0	0.0	0	8,502
SF_OP	34.12	6,666	5,595	83.9	0	0.0	7,062	5,991	84.8	0	0.0	145	7,252
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	4,179	3,447	82.5	0	0.0	646	6,887
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,868	3,222	83.3	0	0.0	613	7,033
SUM_P	44.35	5,773	5,131	88.9	0	0.0	6,381	5,740	90.0	0	0.0	182	8,125
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,330	4,031	93.1	0	0.0	21	8,695
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	9,551	8,144	85.3	0	0.0	109	7,316
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,503	9,576	91.2	0	0.0	0	8,324
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	11,271	9,737	86.4	0	0.0	87	7,493

This indicates that, even absent the transaction, FPL's natural expansion in generation capacity to meet growing demand would result in changes to market concentration (as measured by HHI) similar to, or in fact greater than, those observed under the Vandolah acquisition.

6.3. DPT Results for Vandolah in DEF

6.3.1. DPT Results for Alternate Case

Table 14 (identical to Table 3 in the summary) presents summary results for AEC for the Alternate Case in DEF, and the summary results for the plus 10 percent and minus 10 percent price sensitivity are shown in Table 15 and Table 16. The DPT analysis shows that, for the DEF destination in the Alternate Case, the DPT screens are passed for nine of ten periods. The one failure in the Spring/Fall Top 10% case is a false positive. Although NextEra's share increases because of Vandolah, supplies of others do not decrease. Moreover, the DPT does not account for the likely competitive response from DEF. Following the Transaction, DEF would likely develop new power generation resources to replace the loss of Vandolah to service its retail load obligations. As a result, the DPT results indicate that the Transaction raises no potential competition concern in the DEF destination market. This single screen failure also occurs in the +10% price sensitivity, but Table 16 shows that it disappears in the -10% price sensitivity.

Table 14: Summary Results for AEC in DEF, Alternate Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	648	29.5	0	0.0	139	1,727
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

Table 15: Summary Results for AEC in DEF, +10% Prices, Alternate Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	2,196	662	30.1	0	0.0	384	1,776
SF_P	37.33	1,730	86	5.0	636	36.8	1,730	86	5.0	636	36.8	0	2,351
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,525	398	15.7	928	36.7	-304	2,252
SUM_T1	68.55	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_T10	60.80	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_P	42.37	1,032	0	0.0	0	0.0	1,032	0	0.0	0	0.0	0	3,256
SUM_OP	35.94	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	54.26	2,327	363	15.6	0	0.0	2,327	357	15.3	0	0.0	-6	1,215
WIN_P	38.15	1,633	248	15.2	180	11.0	1,633	248	15.2	180	11.0	0	1,781
WIN_OP	38.18	2,796	573	20.5	370	13.2	2,796	573	20.5	370	13.2	0	1,717

Table 16: Summary Results for AEC in DEF, -10% Prices, Alternate Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	2,193	604	27.6	0	0.0	48	1,614
SF_P	30.55	1,046	53	5.1	0	0.0	1,046	53	5.1	0	0.0	0	2,512
SF_OP	28.33	817	44	5.3	0	0.0	817	44	5.3	0	0.0	0	3,510
SUM_T1	56.09	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_T10	49.74	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_P	34.67	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	29.40	557	0	0.0	0	0.0	557	0	0.0	0	0.0	0	8,611
WIN_T10	44.40	2,190	398	18.2	0	0.0	2,190	389	17.8	0	0.0	-10	1,309
WIN_P	31.21	1,096	72	6.5	0	0.0	1,096	72	6.5	0	0.0	0	2,273
WIN_OP	31.24	1,006	46	4.6	0	0.0	1,006	46	4.6	0	0.0	0	2,513

First-Tier Markets. Exhibit No. JM-11 contains the AEC results for first-tier markets for the Alternate Case. There are isolated screen failures in the FMPP, GVL, and TEC BAAs. Most of these occur in the TEC BAA. In that case, DEF does not supply AEC to TEC in the base price and -10% price sensitivities, and DEF supplies relatively little in the +10% case. This is consistent with the position that the transaction does not reduce competition in Florida. In addition, no screen failures were observed in any season for the FPL, SEC, SOCO, and TAL BAAs. Table 17 presents the AEC results in the FPL BAA. There are no screen failures in any periods for the base price and price sensitivity cases. See Exhibit No. JM-11.

Table 17: Summary Results for AEC in FPL BAA, Alternate Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,354	2,622	78.2	0	0.0	0	6,241
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,108	2,462	79.2	0	0.0	0	6,420
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,773	5,131	88.9	0	0.0	0	7,944
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

Overall, the DPT results suggest that, under the Alternate Case, the proposed Transaction does not raise major competitive concerns.

6.3.2. DPT Results for Alternate Case with Mitigation Measure

We model the temporary mitigation by assuming that FPL would divest two out of the four units at the Vandolah facility after the Transaction. Table 18 (identical to Table 7 in the summary) presents summary results for AEC for the Alternate Case with the proposed mitigation for the DEF BAA destination market. The results for price sensitivity tests and AEC and EC for first-tier markets are included in Exhibit JM-12. DPT results show that no screen failures occur in FPL or DEF in any periods. The proposed temporary mitigation eliminates all screen failures except for the Summer

Peak in TEC for the +10% price case and the Winter Top 10% in FMPP; but, for the same reasons stated above, they should not cause the Commission concern.

Table 18: Summary Results for AEC with Mitigation Measure in DEF BAA, Alternate Case

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	363	16.5	0	0.0	-291	1,298
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	297	14.6	0	0.0	-692	1,550
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	297	14.7	0	0.0	-694	1,553
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

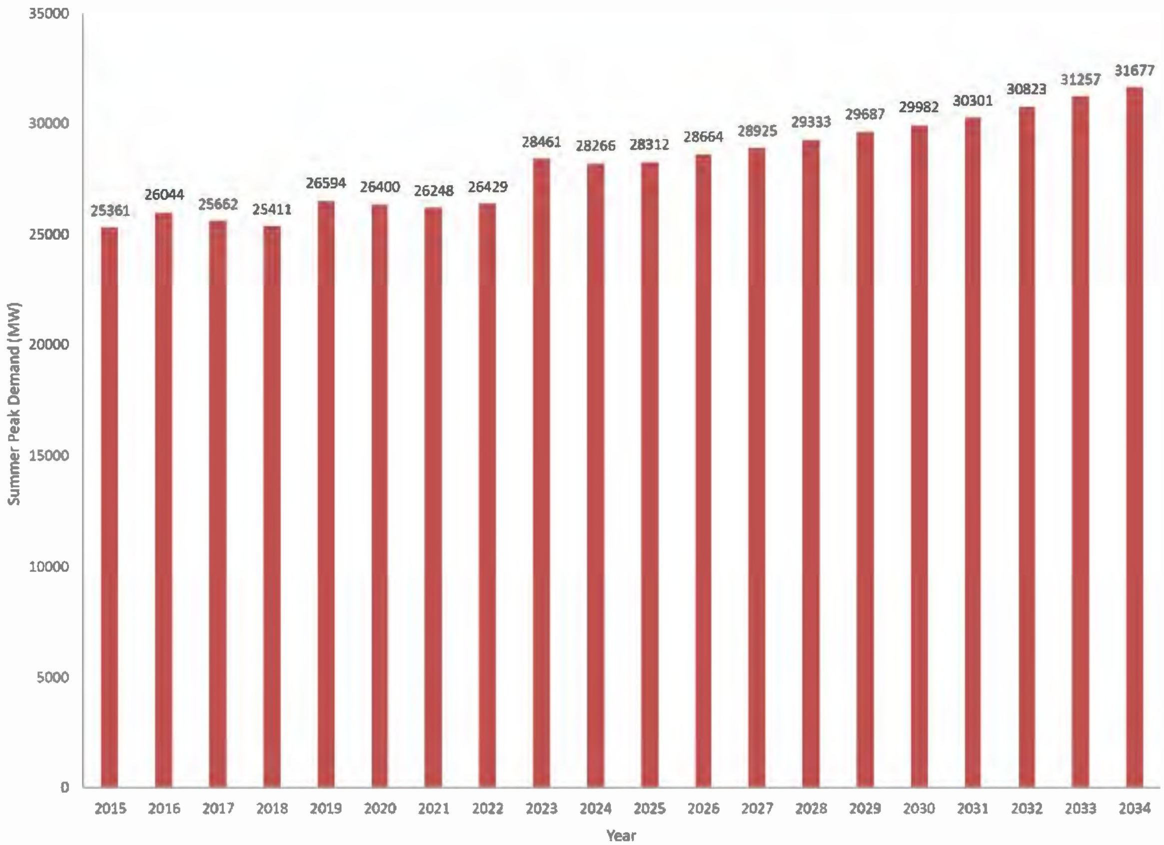
To summarize, in the event that the new transmission is not complete by Transaction close, I conclude that the Transaction, even absent mitigation, does not raise horizontal market power concerns. Nonetheless, the proposed mitigation cures the screen failures and provides an additional safeguard to further ensure that no competitive concerns arise.

7. Factors Limiting the Time for Temporary Mitigation

7.1. Load Growth

The expected load growth in the FPL BAA limits the need for a prolonged mitigation period. As load increases over time, FPL's AEC relative to market demand naturally declines, thereby reducing its market share and mitigating any competitive concerns. Thus, load growth reduces the potential for the exercise of market power and supports the conclusion that the proposed mitigation measures need not extend beyond the near term. Figure 1 presents FPL's historical and projected summer peak demand based on its Ten-Year Power Plant Site Plan. Between 2015 and 2024, actual summer peak demand increased from 25,361 MW to 28,266 MW, reflecting an average annual growth of 323 MW per year. For the period 2025 to 2034, FPL projects an increase from 28,312 MW to 31,677 MW, or approximately 374 MW per year. Given that the Vandolah facility has a capacity of 660 MW, FPL would conservatively need to add generation equivalent to one Vandolah facility roughly every two years to meet projected demand growth, without taking into account other considerations that inform resource planning, such as planning reserve margins or probabilistic loss of load assessments.

Figure 1: FPL Historic and Projected Peak Summer Demand (MW)



Source: Florida Power and Company: 2025 – 2034 Ten Year Power Plant Site Plan, Schedule 3.1.

7.2. Time for New Generation Construction

The mitigation measure—designed to address a temporary increase in Available Economic Capacity (AEC) due to the transaction—should be limited in duration to reflect the time needed to construct new generation. As the Commission has stated, long-term markets for generation are inherently competitive because of the ability to construct new generation.[45] Adding Vandolah to the FPL generation fleet replaces the need for new battery development that FPL would otherwise undertake to meet future load obligations. According to the Energy Information Administration ("EIA"), the median time from the signing of an interconnection agreement to the commercial operation date for utility-scale solar projects in the U.S. is approximately 25 months.[46] This duration encompasses permitting, construction, and testing phases. Constructing a utility-scale solar facility in Florida typically requires approximately 24 to 36 months, including permitting, interconnection, and construction.[47] The construction and operation of a battery site or solar paired with batteries can also be accomplished within this period.[48] Because the Transaction has been publicly announced approximately two years prior to the expiration of the Vandolah contract with Duke and FPL taking control of Vandolah, these data suggest that no mitigation would be necessary because alternative supplies could be constructed before FPL takes control of Vandolah. Even if the Commission would consider that only a similar facility would be an adequate replacement, ignoring that most new generation in Florida are now solar and battery resources, then the interim mitigation should be limited in duration to the five years it takes to build combustion turbines in FL, recognizing current supply chain limitations.[49] Finally, the Commission should not require mitigation that lasts any longer than when FPL might otherwise place an equivalent amount of capacity in service to meet growing demand. According to FPL's current ten-year plan, FPL projects 400 MW of batteries that will be placed in service

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45 See Market-Based Rates for Wholesale Sales of Electric 19 Energy, Capacity and Ancillary Services by Public Utilities, Order No. 697, 119 FERC ¶ 61,295 (2007), at P 122.

46 EIA, Today in Energy, May 8, 2024.

47 Direct Testimony of Tim Oliver, EC25-__-000, June 9, 2025.

48 *Id*.

49 *Id*. at 12.

by 2028 and 475 MW of CT capacity coming online by 2032, [50] but FPL will not need to build this capacity if it acquires Vandolah. [51] This suggests that the interim mitigation would be necessary only through the end of 2031 at the very latest.

8. Historical Data Confirm No Material Decrease in Competition

Historical data verify the results of the DPT analysis presented here that the transaction does not enhance market power.[52] Exhibit JM-13 provides an HHI calculation based on Electric Quarterly Reports ("EQR") data for 2023-2024 for deliveries in the FPL BAA and all first-tier markets.[53] In 2023-2024, DEF sold only 1,323 MWh in the FPL BAA. By contrast, 3.24 million MWh of energy were sold at wholesale in the FPL BAA in 2024. See Exhibit No. JM-13. The sales by DEF thus represented merely 0.04 percent of the total wholesale market—a truly *de minimis* amount. To measure the effect of the transaction, I assume that Duke's share of sales post-transaction falls to zero and NextEra (FPL) captures all the lost sales in the market. As expected, wholesale energy sales in the FPL BAA are highly concentrated as measured by the HHI of 2,058, as it is in all the EC scenarios. However, the Duke Energy Florida share is very small; in fact, it rounds to zero at one decimal place. The change in the HHI is therefore negligible. This confirms that the Transaction does not result in a loss of competition in the FPL BAA.

Exhibit JM-14 provides an alternative historical HHI calculation based on EIA

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50 Florida Power & Light, Ten Year Power Plant Site Plan 2025-2034, P 9.

51 Whitley Testimony at 14-15

52 18 C.F.R. §33.3(c)(6) ("The applicant must provide historical trade data and historical transmission data to corroborate the results of the horizontal Competitive Analysis Screen. The data must cover the two-year period preceding the filing of the application.").

53 *Id.*

Form 923 data for 2023-2024,[54] which gives monthly output by generation plant, prime mover, and fuel type. These data show generation of energy in the FPL is highly concentrated with a pre-transaction HHI of 9,598. To estimate a change from the transaction, we add the energy generated from Vandolah (1,437,983 MWh) to the NextEra generation. With rounding, the post-transaction share does not change because the market size increases by the same amount of the Vandolah generation. The net effect is that the HHI changes by 2. The net effect in the DEF BAA is the opposite but still insignificant. In terms of total generation, Duke's generation would fall by 1,437,983 MWh (assuming no replacement generation), and the total generation falls by the same amount. The net effect is that Duke's share of generation falls from 93.4% to 93.2%, and the HHI falls by 21 from 8,726 to 8,705.

Therefore, historical sales and generation data confirm that the Transaction has no material impact in competition in DEF and FPL BAAs.

9. Other Competitive Issues

The Transaction does not raise concerns in any capacity market because neither FPL nor DEF participates in a centralized capacity market in Florida. Instead, load-serving entities in Florida meet their capacity obligations through self-supply or bilateral contracts. As a result, the Transaction does not alter participation or outcomes in any capacity market, nor does it create the ability or incentive to withhold capacity to influence market prices. Therefore, there is no basis for concern that the Transaction would harm competition in a capacity market.

The Transaction does not raise concerns in the ancillary services market either. FPL and DEF provide ancillary services pursuant to schedules in their Open Access

54 Because the Form 923 data are by plant, I used the ABB, Velocity Suite, Unit Generation and Emissions – Monthly database.

Transmission Tariffs ("OATTs").[55] As such, there is no organized market for ancillary services as would be the case in an RTO. Therefore, the Transaction does not result in any harm to competition in ancillary services markets.

The Transaction also does not raise any vertical market power concerns. Aside from the transmission facilities required to interconnect the Vandolah facility to the grid, no transmission assets are being acquired. Moreover, FPL operates under a Commission-approved OATT, which ensures nondiscriminatory access to the transmission system. As a result, the types of vertical concerns typically evaluated by the Commission are not present in this case, and the Transaction does not create or enhance vertical market power.

Finally, the Transaction presents no issues with respect to fuel costs. NextEra holds interests in the Sabal Trail Transmission, LLC ("Sabal Trail") and Florida Southeast Connection, LLC ("FSC") interstate natural gas pipelines. Both pipelines operate under open-access tariffs approved by FERC, which prohibit the pipeline operators from withholding capacity or denying service to any market participant that satisfies the conditions outlined in their respective FERC Gas Tariffs. In addition to these interstate assets, NextEra also owns the Lowman intrastate pipeline in Alabama that is subject to state regulatory oversight. These federal and state regulatory frameworks are designed to prevent any entity with ownership interests in natural gas pipelines from exercising market power.

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55 FPL and DEF provide ancillary services pursuant to the following Schedules of its OATT: SCHEDULE 1--Scheduling, System Control and Dispatch Service; SCHEDULE 2--Reactive Supply and Voltage Control from Generation or Other Sources Service; SCHEDULE 3--Regulation and Frequency Response Service; SCHEDULE 4--Energy Imbalance Service; SCHEDULE 5--Operating Reserve - Spinning Reserve Service; SCHEDULE 6--Operating Reserve - Supplemental Reserve Service; SCHEDULE 9--Generator Imbalance Service.

10. Conclusion

This report examines the impact of the proposed Transaction on competition in the short-term electric power markets. Although there are some screen failures, they are driven by an increase in FPL's AEC rather than a reduction in competitive supply. In addition, the Transaction's effect on HHI is similar in magnitude to the effect that would result from a natural increase in FPL's generation supply to meet rising demand. Moreover, should the Commission find any potential competitive concerns arising from the Transaction, any such competitive concerns are temporary, and are addressed by the proposed mitigation measure, which cures the identified screen failures in the FPL market. Finally, the proposed Transaction has no effects in the capacity and ancillary services markets.

As a result, I recommend that the Commission conclude that the Transaction with the proposed temporary mitigation plan will not adversely affect competition in wholesale electric power markets.

Pursuant to 28 U.S.C. §1746, I state under penalty of perjury that the foregoing is true and correct to the best of my information, knowledge, and belief.

Executed on this 10th day of June 2025.

John R. Morris, Ph.D.
Managing Director
Secretariat Advisors LLC

EXPERIENCE AND QUALIFICATIONS OF
Dr. John R. Morris

OVERVIEW	Dr. Morris, a recognized expert in studying competition and price formation in energy industries, currently is a Managing Director at Secretariat Advisors LLC (formerly Economists Incorporated). He began his research of competition in energy industries in 1985 while working for the Federal Trade Commission. Since joining Economists Incorporated in 1992, he has consulted on many mergers and acquisitions involving energy companies, examined competitive issues relating to rates, and studied issues in state restructuring proceedings. He has published articles on competition and energy matters, and he has spoken on numerous occasions concerning competition in natural gas, electric power and other industries. He has been accepted as an expert witness on energy matters before the Federal Energy Regulatory Commission, state regulatory commissions, and in federal court.
EDUCATION	Ph.D., University of Washington, August 1985 Dissertation: *Intellectual Property: Creating, Pricing, Copying* • M.A., University of Washington, December 1983 • A.B., Georgetown University, May 1981
PRESENT POSITION	Dr. Morris is a *Managing Director* at Secretariat Advisors LLC, an economic consulting firm located at 2121 K Street, NW, Suite 1100, Washington, DC 20037. (202-223-4700) Secretariat Advisors studies competition and regulation in many industries in the United States and in other countries. It is a leading firm in studying the competitive effects of mergers and acquisitions, damages, construction costs, and construction delay.
PREVIOUS EXPERIENCE	*Principal*, Economists Incorporated, December 2002 – July 2021 • *Senior Vice President*, Economists Incorporated, December 2001 – December 2002 • *Vice President*, Economists Incorporated, December 1995 – December 2001 • *Senior Economist*, Economists Incorporated, June 1992 – December 1995 • *Economic*

Tutorial Leader, Stanford University (Stanford in Washington), April 1993 – June 1995 • *Visiting Assistant Professor,* Department of Business Economics and Public Policy, School of Business, Indiana University, September 1991 – May 1992 • *Assistant to the Director for Antitrust,* Bureau of Economics, Federal Trade Commission, November 1989 – August 1991 • *Economic Advisor,* Office of Commissioner Machol, Federal Trade Commission, December 1988 – October 1989 • *Economist,* Division of Antitrust, Bureau of Economics, Federal Trade Commission, October 1985 – December 1988

MEMBERSHIPS

Member, International Association of Energy Economics • Associate, Energy Bar Association • Member, American Economic Association • Member, Western Economic Association International • Associate, American Bar Association

AWARDS & HONORS

Award for Excellence in Law Enforcement, Federal Trade Commission, 1988 • Graduate School Scholarship, University of Washington, 1984 • Graduated Cum Laude Georgetown University, 1981 • Senior Comprehensive Passed with Distinction, Georgetown University, 1981

TESTIMONY BEFORE THE FEDERAL ENERGY REGULATORY COMMISSION

Prepared Answering Testimony and Deposition Affidavit, Public Utilities Commission of the State of California v. Sellers of Long-Term Contracts to the California Department of Water Resources, Docket Nos EL02-60-017 and EL02-60-18 (2025) •Milford Gen Lead, LLC, FERC Docket No. ER24-3102-000 (2024) • Prepared Direct Testimony, Algonquin Gas Transmission, LLC, Docket No. RP24-781 (2024) • Prepared Testimony, Louisiana Public Service Commission *et al.*, v. System Energy Resources, Inc., *et al.*, Docket No. EL21-56 (2024) • Affidavit, Elliott Associates, L.P., *et al.*, Docket No. EC23-112 (2023) • Affidavit, Tampa Electric Company, ER10-1437 (2023) • Affidavits (2), NextEra Energy Resources, LLC, *et al.*, Docket No. EC23-36-000 (2022, 2023) • Affidavits, Building for the Future Through Electric Regional

Transmission Planning and Cost Allocation and Generator Interconnection, Docket No. RM21-17-000 (2022) • Affidavit, NRG Energy, Inc., Docket No. EC20-96-000 (2020) • Affidavit, Energy Texas, Inc., EC20-85-000 (2020) • Affidavit, Tampa Electric Company, ER10-1437-011 (2020) • Affidavits, American Transmission System, Inc., Docket No. ER20-1740-000 (2020) • Affidavits, NRG Wholesale Generation LP and Entergy Mississippi, LLC Docket No. EC19-63-000 (2019) • Affidavits, Louisville Gas and Electric Co. and Kentucky Utilities Co., Docket Nos. EC98-2-001, ER18-2162-000 (2018) • Affidavit, Upper Peninsula Power Company, Docket No. ER10-1901-011 (2018) • Affidavit, NRG Cottonwood Tenant LLC, ER18-1160-001 (2018) • Affidavit, PSEG Energy Resources & Trade LLC, ER10-1789-005 (2018) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-002 (2017) • Affidavit, PSEG Keys Energy Center LLC, ER17-2426-000 (2017) • Affidavit, Tampa Electric Company, ER10-1437-006 (2017) • Prepared Answering Testimony, Deposition, and Hearing, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. British Columbia Power Exchange, *et al.*, EL02-71-000 (2017) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-004 (2016) • Affidavit, Alabama Power Company, *et al.*, ER17-514-00 (2016) • Affidavits (3), Alabama Power Company, *et al.*, EL15-39-000 (2016) • Affidavit, Combined Locks Energy Center, LLC, *et al.* , ER10-3042-004 (2015) • Affidavit, Alabama Power Company, *et al.*, EL15-39-000 (2015) • Affidavit, PJM Interconnection, L.L.C., ER15-623-000 (2015) • Affidavit, Southern Indiana Gas and Electric Co. d/b/a Vectren Energy Delivery of Indiana, Inc., ER10-1338-000 (2014) • Affidavit, Quantum Choctaw Power, LLC *et al.*, ER12-458-007 (2014) • Affidavit, NRG Power Marketing LLC, *et al.*, ER10-2265-004 *et al.* (2014) • Affidavit, TransCanada Entities, ER10-2870-004 *et al.* (2014) • Affidavit, Tampa Electric Company, ER10-1437-002 (2014) • Affidavit, Kendall Green Energy LLC, ER14-1363-003 (2014) • Affidavit, Quantum Lake Power, LP, ER13-1489-000 (2014) • Affidavit, NRG Power Marketing LLC, *et al.* ER10-2265-002 (2014) • Affidavit, NRG Yield, Inc., *et al.*, EC14-101-000 (2014) • Affidavit, Community Wind Farm 1 et al., ER14-1668-000 (2014) • Seaway Crude Pipeline Company LLC, OR15-6-000 (2014) • Affidavit, Public Service Electric and Gas Company *et al.*, ER10-1789-003 (2013) • Affidavits, NRG Energy Holdings, Inc., Edison Mission Energy, EC14-14-000 (2013) • Affidavit, Silver Merger Sub, Inc., *et al.*, EC13-128-000 (2013) • Prepared Answering Testimony, Deposition, and Hearing, Puget Sound Energy, Inc., *et al.*, EL01-10-085 (2012) • Affidavit, Wisconsin Public Service Corporation, *et al.*, ER10-1894-004 (2012) • Affidavit, PSEG New Haven LLC, ER12-1250-000 (2012) • Affidavit, Enterprise Product Partners L.P. and Enbridge, Inc., OR12-4-000 (2012) • Affidavit, Southern Indiana Gas and Electric Co., ER10-1338-001 (2011) • Affidavit, TransCanada Power Marketing Ltd. *et al.*, ER10-2780-001 (2011) • Affidavit, Tampa Electric Company, ER10-1476-001 (2011) • Affidavit, Cedar Creek Wind Energy, LLC, ER11-2577-000 (2010) • Affidavit, Public Service Electric and Gas Company *et al.*, ER97-837-014 (2010) • Affidavit, Morris Energy Group, LLC v. PSEG Energy Resources & Trade LLC; PSEG Fossil LLC; and PSEG Power LLC, EL10-79-000 (2010) • Affidavit, UGI Storage Company and UGI Central Penn Gas, Inc., CP10-23-000 (2010) • Prepared Answering Testimony, People of the State of California, *ex rel*; Bill Lockyer, Attorney General of the State of California v. Powerex Corp., *et al.*, EL02-71-000 (2009) • Affidavit, Integrys Energy Services, Inc. v. New Brunswick Power Generation Corporation, EL09-32-002 (2009) • Affidavit, People of the State of California, *ex rel*; Edmund G. Brown Jr. Attorney General of the State of California v. Powerex Corp., *et al.*, EL09-56-000 (2009) • Affidavit, San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Services, EL00-95-000 (2009) • Affidavit, Troy Energy, LLC, *et al.*, ER02-25-010 (2009) • Affidavit, Combined Locks Energy Center, LLC, *et al.*, ER01-2659-015 (2009) • Prepared Direct Testimony and

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Kalt), Energy Transfer Partners, *et al.*, IN06-3-002 (2008) • Affidavit, Energy Transfer Partners, *et al.*, IN06-3-002 (2008) • Affidavit, TransCanada Maine Wind Development Inc., ER08-685-000 (2008) • Affidavit, O'Connor & Hewitt, LTD, RP08-30-000 (2007) • Affidavit (with Joseph P. Kalt), Energy Transfer Partners, *et al.*, IN06-3-000 (2007) • Affidavit, Energy Transfer Partners, *et al.*, IN06-3-000 (2007) • Affidavit, The People of the State of Illinois, *ex rel.* Illinois Attorney General Lisa Madigan v. 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Report, Deposition and Bench Trial, Entergy Arkansas, LLC, vs. Ted J. Thomas, in his official capacity as Chairman of the Arkansas Public Service Commission et al., Civil Action No. 4:20-cv-01088-KGB, U.S. Dist. Court, Dist. of Eastern Arkansas (2022, 2023) • Reports and Deposition, Duke Energy Carolinas, LLC, vs. NTE Carolinas II, LLC, NTE Carolinas II Holdings, LLC, NTE Energy LLC, NTE Southeast Electric Company, LLC, NTE Energy Services Co., LLC, and Castillo Investment Holdings II, LLC, vs. Duke Energy Progress, LLC and Duke Energy Corporation, Civil Action No. 3:19-cv-515, U.S. Dist. Court, (2022) • Report, Deposition, and Bench Trial, FTC v. Arch Coal, Inc., et al., Civil Action 04-0534 (JDB), U.S. Dist. Court, Dist. of Western North Carolina (2004) • Report, Deposition and Jury Trial, Trigen v. OG&E, CIV-96-1595L, U.S. Dist. Court, Western Dist. of Oklahoma (1998)

TESTIMONY BEFORE STATE COURTS	Report and Deposition, CPS Energy v. Houston Pipe Line Company, LP and Oasis Pipeline, LP, Cause No. 2021-CI- 05138, District Court of Bexar County, Texas, 407th Judicial District (2023-4) • Affidavit, Retail Energy Supply Association, *et al.* v. Public Service Commission of the State of New York, *et al.*, Index No. 870-16, State of New York, Supreme Court, County of Albany (2016) • Affidavit, City Public Service Board of San Antonio vs. Public Utility Commission of Texas, et al., No. 97-02917, District Court of Travis County, Texas, 200th Judicial District (1997)
OTHER TESTIMONY	Report, Metromedia Energy, Inc. v. Mirant Americas Energy Marketing, RE: 18 198 Y 18484 03 (2005) • Report and Deposition, King Provision Corporation v. Burger King Corporation and Grand Metropolitan PLC, 90-05718-CA, 4th Cir., Duval Co., Florida (1992) • Deposition, West Texas Transmission L.P. v. Enron Corp. et al., SA 88 CA 0638, W.D. Texas, San Antonio Division (1988)
PUBLICATIONS	"Alternative Measures of 'Representative Market Prices' for FERC Delivered Price Tests," *Energy Law Journal* 42 (2021): 191-235 • "Should market power still be a concern in the U.S. electric power industry?" with Jéssica Dutra and Tristan SnowCobb, *Electricity Journal* 33 (May 2020): 106725-28 • "Geographic Market Delineation in LMP Electric Power Markets," with Megan Accordino, *Electricity Journal* 23(3) (April 2010): 49-60 • "The Likely Effect of the Proposed Exelon-PSEG Merger on Wholesale Electricity Prices," with Dan Oska, *Electricity Journal* 21(1) (Jan./Feb. 2008): 45-54 • "FERC MBR Screens: The Good, the Bad, and the Ugly," *Public Utilities Fortnightly* 143(7) (July 2005): 37-42 • "Finding Market Power in Power Markets," *International Journal of the Economics of Business*, 7(2) (July 2000): 167-178 • "Why Applicants Should Use Computer Simulation Models to Comply with the FERC's New Merger Policy," with Mark Frankena, *Public Utilities Fortnightly*, 135(3) (February 1, 1997): 22-26 • *Electric Utility Mergers,* with Mark

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NextEra Energy Generation in FPL and First-Tier Areas

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
DEF							
Bell Ridge Solar	PV1		74.5	74.5	100.0	74.5	74.5
Columbia County Solar Project	PV1		74.5	74.5	100.0	74.5	74.5
Gadsden County Solar Project	PV1		74.5	74.5	100.0	74.5	74.5
Gilchrist County Solar	PV1		74.5	74.5	100.0	74.5	74.5
Total NextEra Owned Capacity in DEF						**298.0**	**298.0**
Contracts							
Bell Ridge Solar	PV1					-74.5	-74.5
Columbia County Solar Project	PV1		74.5	74.5	100.0	-74.5	-74.5
Gadsden County Solar Project	PV1		74.5	74.5	100.0	-74.5	-74.5
Gilchrist County Solar	PV1		74.5	74.5	100.0	-74.5	-74.5
Total NextEra Contracts in DEF						**-298.0**	**-298.0**
NextEra Net Generation in DEF						**0.0**	**0.0**
FMPP							
Harmony Florida Solar	PV2		74.5	74.5	100.0	74.5	74.5
Harmony Florida Solar II	PV3		74.5	74.5	100.0	74.5	74.5
Stanton Energy Center	CC 1		657.0	657.0	65.0	427.1	427.1
Total NextEra Owned Capacity in FMPP						**576.1**	**576.1**
Contracts							
Harmony Florida Solar	PV2		74.5	74.5	100.0	-74.5	-74.5
Harmony Florida Solar II	PV3		74.5	74.5	100.0	-74.5	-74.5
Stanton Energy Center	CC 1		657.0	657.0	65.0	-427.1	-427.1
Total NextEra Contracts in FMPP						**-576.1**	**-576.1**
NextEra Net Generation in FMPP						**0.0**	**0.0**
FPL							
Big Water Solar	PV1	2025	74.5	74.5	100.0	74.5	74.5

			Capacity (MW)			Inputted Capacity (MW)	
Plant Name	Unit	Start Year	Summer	Winter	Ownership Share (%)	Summer	Winter
Crystal Mine Solar (Speckled Perch)	PV1	2025	74.5	74.5	100.0	74.5	74.5
Fawn Solar	PV1	2025	74.5	74.5	100.0	74.5	74.5
Fox Trail	PV1	2025	74.5	74.5	100.0	74.5	74.5
Green Pasture	PV1	2025	74.5	74.5	100.0	74.5	74.5
Hog Bay Solar Energy Center	PV1	2025	74.5	74.5	100.0	74.5	74.5
Holopaw Solar Energy Center	PV1	2025	74.5	74.5	100.0	74.5	74.5
Long Creek Solar	PV1	2025	74.5	74.5	100.0	74.5	74.5
Redlands Solar	PV1	2025	74.5	74.5	100.0	74.5	74.5
Swallowtail Solar Energy Center	PV1	2025	74.5	74.5	100.0	74.5	74.5
Tenmile Creek	PV1	2025	74.5	74.5	100.0	74.5	74.5
Thomas Creek Solar Energy Center	PV1	2025	74.5	74.5	100.0	74.5	74.5
Boardwalk	PV1	2026	74.5	74.5	100.0	74.5	74.5
Mare Branch Solar	PV1	2026	74.5	74.5	100.0	74.5	74.5
North Orange Solar	PV1	2026	74.5	74.5	100.0	74.5	74.5
Price Creek	PV1	2026	74.5	74.5	100.0	74.5	74.5
Swamp Cabbage Solar Energy Center	PV1	2026	74.5	74.5	100.0	74.5	74.5
Anhinga Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Apalachee Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Babcock Preserve Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Babcock Ranch Solar	BA1		10.0	10.0	100.0	10.0	10.0
Babcock Ranch Solar	PV1		74.5	74.5	100.0	74.5	74.5
Barefoot Bay Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Beautyberry	PV1		74.5	74.5	100.0	74.5	74.5
Big Juniper Solar	PV1		74.5	74.5	100.0	74.5	74.5
Blackwater River Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Blue Cypress Solar	PV1		74.5	74.5	100.0	74.5	74.5
Blue Heron Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Blue Indigo Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Blue Springs Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Bluefield Preserve Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Buttonwood Solar	PV1		74.5	74.5	100.0	74.5	74.5
Caloosahatchee Solar	PV1		74.5	74.5	100.0	74.5	74.5
Canoe Solar	PV1		74.5	74.5	100.0	74.5	74.5
Cape Canaveral Energy Center	CC		1,290.0	1,393.0	100.0	1,290.0	1,393.0

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
Cattle Ranch Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Cavendish Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Cedar Trail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Chautauqua Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Chipola River Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Citrus Solar Energy Center	BA1		4.0	4.0	100.0	4.0	4.0
Citrus Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Coral Farms Solar	PV1		74.5	74.5	100.0	74.5	74.5
Cotton Creek Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Crist (Gulf Clean Energy Center)	10		231.1	231.1	100.0	231.1	231.1
Crist (Gulf Clean Energy Center)	11		231.1	231.1	100.0	231.1	231.1
Crist (Gulf Clean Energy Center)	4		75.0	75.0	100.0	75.0	75.0
Crist (Gulf Clean Energy Center)	5		75.0	75.0	100.0	75.0	75.0
Crist (Gulf Clean Energy Center)	6		299.0	299.0	100.0	299.0	299.0
Crist (Gulf Clean Energy Center)	7		475.0	475.0	100.0	475.0	475.0
Crist (Gulf Clean Energy Center)	8		236.0	233.0	100.0	236.0	233.0
Crist (Gulf Clean Energy Center)	9		236.0	233.0	100.0	236.0	233.0
Desoto Next Generation Solar Energy Center	PV1		25.0	25.0	100.0	25.0	25.0
Discovery Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Echo River Solar Energy Center	BA1		30.0	30.0	100.0	30.0	30.0
Echo River Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Egret Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Elder Branch Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Everglades Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
FIU Solar	PV1		0.8	0.8	100.0	0.8	0.8
FPL Cypress Pond Solar	PV1		74.5	74.5	100.0	74.5	74.5
FPL Etonia Creek	PV1		74.5	74.5	100.0	74.5	74.5
FPL Saw Palmetto Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
FPL Shirer Branch Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
First City Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Flowers Creek Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Fort Drum Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Fort Myers	3A		182.0	200.0	100.0	182.0	200.0
Fort Myers	3B		182.0	200.0	100.0	182.0	200.0

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
Fort Myers	3C		231.0	223.0	100.0	231.0	223.0
Fort Myers	3D		231.0	223.0	100.0	231.0	223.0
Fort Myers	9		54.0	61.5	100.0	54.0	61.5
Fort Myers	CC1		1,801.5	1,787.0	100.0	1,801.5	1,787.0
Fort Myers	GT1		54.0	61.5	100.0	54.0	61.5
Fourmile Creek	PV1		74.5	74.5	100.0	74.5	74.5
Georges Lake Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Ghost Orchid Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Grove Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Hammock Solar	PV1		74.5	74.5	100.0	74.5	74.5
Hawthorne Creek Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Hendry Isles Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Hibiscus Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Honeybell Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Horizon Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Ibis	PV1		74.5	74.5	100.0	74.5	74.5
Immokalee Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Indian River Solar	PV1		74.5	74.5	100.0	74.5	74.5
Interstate Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Kayak Solar	PV1		74.5	74.5	100.0	74.5	74.5
Kennedy Space Coast Next Generation Solar Energy Ce	PV1		10.0	10.0	100.0	10.0	10.0
Lakeside Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Lansing Smith	CC		660.0	646.0	100.0	660.0	646.0
Lansing Smith	CT1		32.0	40.0	100.0	32.0	40.0
Lauderdale	3		34.3	37.2	100.0	34.3	37.2
Lauderdale (Dania Beach)	CC7		1,246.0	1,234.0	100.0	1,246.0	1,234.0
Lauderdale	GT5		34.3	37.2	100.0	34.3	37.2
Lauderdale	PFL6A		231.0	222.0	100.0	231.0	222.0
Lauderdale	PFL6B		231.0	222.0	100.0	231.0	222.0
Lauderdale	PFL6C		231.0	222.0	100.0	231.0	222.0
Lauderdale	PFL6D		231.0	222.0	100.0	231.0	222.0
Lauderdale	PFL6E		231.0	222.0	100.0	231.0	222.0
Loggerhead Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Magnolia Springs Solar Center	PV1		74.5	74.5	100.0	74.5	74.5

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
Manatee (FPL)	1		809.0	819.0	100.0	809.0	819.0
Manatee (FPL)	2		809.0	819.0	100.0	809.0	819.0
Manatee (FPL)	3		1,133.0	1,265.0	100.0	1,133.0	1,265.0
Manatee Energy Storage Center	BA1		409.0	409.0	100.0	409.0	409.0
Manatee Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Martin (FL)	CC3		487.0	533.0	100.0	487.0	533.0
Martin (FL)	CC4		487.0	533.0	100.0	487.0	533.0
Martin (FL)	CC5		1,235.0	1,271.0	100.0	1,235.0	1,271.0
Miami Dade Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Mitchell Creek Solar	PV1		74.5	74.5	100.0	74.5	74.5
Monarch Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Nassau Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Nature Trail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Northern Preserve Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Norton Creek Solar	PV1		74.5	74.5	100.0	74.5	74.5
Okeechobee Clean Energy Center	CC1		1,723.1	1,723.1	100.0	1,723.1	1,723.1
Okeechobee Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Oleander Power Project	OG1		163.8	180.0	100.0	163.8	180.0
Oleander Power Project	OG2		163.0	180.0	100.0	163.0	180.0
Oleander Power Project	OG3		163.0	180.0	100.0	163.0	180.0
Oleander Power Project	OG4		163.0	180.0	100.0	163.0	180.0
Oleander Power Project	OG5		163.0	180.0	100.0	163.0	180.0
Orange Blossom Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Orchard Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Palm Bay Solar	1		74.5	74.5	100.0	74.5	74.5
Pea Ridge	1		4.0	4.6	100.0	4.0	4.6
Pea Ridge	2		4.0	4.6	100.0	4.0	4.6
Pea Ridge	3		4.0	4.6	100.0	4.0	4.6
Pecan Tree Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Pelican Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Pembroke Lakes Mall PV	PV1		1.1	1.1	100.0	1.1	1.1
Perdido Landfill	IC1		1.5	1.5	100.0	1.5	1.5
Perdido Landfill	IC2		1.5	1.5	100.0	1.5	1.5
Pineapple Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
Pink Trail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Pioneer Trail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Port Everglades	CC1		1,237.0	1,338.0	100.0	1,237.0	1,338.0
Prairie Creek Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Riviera	CC		1,290.0	1,393.0	100.0	1,290.0	1,393.0
Rodeo Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Sabal Palm Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Sambucus Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Sanford (FL)	4CC		1,176.0	1,188.0	100.0	1,176.0	1,188.0
Sanford (FL)	5CC		1,176.0	1,188.0	100.0	1,176.0	1,188.0
Sawgrass Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Silver Palm Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Solar Research Center at Florida Intl University	PV1		1.0	1.0	100.0	1.0	1.0
Southfork Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Sparkleberry Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
St Johns County Solar Project	PV1		74.5	74.5	100.0	74.5	74.5
St Lucie	1		981.0	1,003.0	100.0	981.0	1,003.0
St Lucie	2		987.0	987.0	92.5	913.3	913.3
Sundew Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Sunshine Gateway Solar Energy Center	BA1		30.0	30.0	100.0	30.0	30.0
Sunshine Gateway Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Sweetbay Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
Terrill Creek Solar	PV1		74.5	74.5	100.0	74.5	74.5
Three Creeks Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Tupelo Solar	PV1		74.5	74.5	100.0	74.5	74.5
Turkey Point	3		837.0	859.0	100.0	837.0	859.0
Turkey Point	4		861.0	888.0	100.0	861.0	888.0
Turkey Point	CC		1,254.1	1,288.0	100.0	1,254.1	1,288.0
Turnpike Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Twin Lakes Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Union Springs Solar Center	PV1		74.5	74.5	100.0	74.5	74.5
West County Energy Center	CC1		1,259.0	1,369.0	100.0	1,259.0	1,369.0
West County Energy Center	CC2		1,259.0	1,369.0	100.0	1,259.0	1,369.0
West County Energy Center	CC3		1,259.0	1,369.0	100.0	1,259.0	1,369.0

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
White Tail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Wild Azalea Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Wild Quail Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Wildflower Solar	PV1		74.5	74.5	100.0	74.5	74.5
Willow Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Woodyard Solar Energy Center	PV1		74.5	74.5	100.0	74.5	74.5
Wynwood Energy Storage	BA1		10.0	10.0	100.0	10.0	10.0
Total NextEra Owned Capacity in FPL						**38,936.5**	**40,025.7**
Contracts							
Oleander Power Project	OG1		163.8	180.0	100.0	-163.8	-180.0
Oleander Power Project	OG2		163.0	180.0	100.0	-163.8	-180.0
Oleander Power Project	OG3		163.0	180.0	100.0	-163.8	-180.0
Oleander Power Project	OG4		163.0	180.0	100.0	-163.8	-180.0
Oleander Power Project	OG5		163.0	180.0	100.0	-163.8	-180.0
Tupelo Solar	PV1		74.5	74.5	100.0	-74.5	-74.5
Total NextEra Contracts in FPL						**-893.5**	**-974.5**
NextEra Net Generation in FPL						**38,043.0**	**39,051.2**

SOCO

Cool Springs Solar (GA)	BA1		40.0	40.0	100.0	40.0	40.0
Cool Springs Solar (GA)	PV1		213.0	213.0	100.0	213.0	213.0
Decatur Solar Energy Center	PV1		200.0	200.0	100.0	200.0	200.0
Dougherty County Solar	PV1		120.0	120.0	100.0	120.0	120.0
Live Oak Solar	PV1		51.0	51.0	100.0	51.0	51.0
Quitman II Solar	PV1		150.0	150.0	100.0	150.0	150.0
Quitman Solar	PV1		150.0	150.0	100.0	150.0	150.0
Scherer	3		860.0	860.0	25.0	215.0	215.0
Wadley Solar	PV1		260.0	260.0	100.0	260.0	260.0
Washington County Solar	PV1		150.0	150.0	100.0	150.0	150.0
White Oak Solar	PV1		76.5	76.5	100.0	76.5	76.5
White Pine Solar	PV1		101.2	101.2	100.0	101.2	101.2
Total NextEra Owned Capacity in SOCO						**1,726.7**	**1,726.7**
Contracts							

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
Cool Springs Solar (GA)	PV1		213.0	213.0	100.0	-213.0	-213.0
Decatur Solar Energy Center	PV1		200.0	200.0	100.0	-200.0	-200.0
Dougherty County Solar	PV1		120.0	120.0	100.0	-120.0	-120.0
Live Oak Solar	PV1		51.0	51.0	100.0	-51.0	-51.0
Quitman II Solar	PV1		150.0	150.0	100.0	-150.0	-150.0
Quitman Solar	PV1		150.0	150.0	100.0	-150.0	-150.0
Wadley Solar	PV1		260.0	260.0	100.0	-260.0	-260.0
Washington County Solar	PV1		150.0	150.0	100.0	-150.0	-150.0
White Oak Solar	PV1		76.5	76.5	100.0	-76.5	-76.5
White Pine Solar	PV1		101.2	101.2	100.0	-101.2	-101.2
Total NextEra Contracts in SOCO						**-1,471.7**	**-1,471.7**
NextEra Net Generation in SOCO						**255.0**	**255.0**

Sources: EIA-860M, April 2025; Secretariat DPT Model.

Duke Energy Generation in FPL and First-Tier Areas

Plant Name	Unit	Start Year	Capacity (MW) Summer	Capacity (MW) Winter	Ownership Share (%)	Inputted Capacity (MW) Summer	Inputted Capacity (MW) Winter
DEF							
Vandolah Power Station	G101		165.5	175.5	100.0	165.500	175.500
Vandolah Power Station	G201		165.5	175.5	100.0	165.500	175.500
Vandolah Power Station	G301		165.5	175.5	100.0	165.500	175.500
Vandolah Power Station	G401		163.5	173.5	100.0	163.500	173.500
Total Duke Owned Capacity in DEF						**660.0**	**700.0**
Contracts							
Vandolah Power Station	G101		165.5	175.5	100.0	-165.500	-175.500
Vandolah Power Station	G201		165.5	175.5	100.0	-165.500	-175.500
Vandolah Power Station	G301		165.5	175.5	100.0	-165.500	-175.500
Vandolah Power Station	G401		163.5	173.5	100.0	-163.500	-173.500
Total Duke Contracts in DEF						**-660.0**	**-700.0**
Duke Net Generation in DEF						**0.0**	**0.0**
FMPP							
AdventHealth Solar Project	PV1	2025	3.0	3.0	100.0	3.0	3.0
Duke Net Generation in FMPP						**3.0**	**3.0**
FPC							
Sundance Renewable Energy Center	PV1	2025	74.9	74.9	100.0	74.9	74.9
Anclote	1		508.0	521.0	100.0	508.0	521.0
Anclote	2		497.0	504.0	100.0	497.0	504.0
Bay Ranch Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Bay Trail Solar	PV1		74.9	74.9	100.0	74.9	74.9
Bayboro	P1		37.0	55.0	100.0	37.0	55.0
Bayboro	P2		18.5	27.5	100.0	18.5	27.5

Plant Name	Unit	Start Year	Capacity (MW)		Ownership Share (%)	Inputted Capacity (MW)	
			Summer	Winter		Summer	Winter
Bayboro	P3		40.0	54.0	100.0	40.0	54.0
Bayboro	P4		41.0	56.0	100.0	41.0	56.0
Cape San Blas Energy Storage Project	BA1		5.5	5.5	100.0	5.5	5.5
Charlie Creek Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Columbia Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
County Line Renewable Energy Center	PV1		74.9	74.9	100.0	74.9	74.9
Crystal River	5		710.0	721.0	100.0	710.0	721.0
Crystal River	CC1		807.0	925.0	100.0	807.0	925.0
Crystal River	CC2		810.0	929.0	100.0	810.0	929.0
Crystal River	ST4		712.0	721.0	100.0	712.0	721.0
DeBary Solar Plant	PV1		74.5	74.5	100.0	74.5	74.5
Debary	10		72.0	88.0	100.0	72.0	88.0
Debary	2		45.0	57.0	100.0	45.0	57.0
Debary	3		45.0	59.0	100.0	45.0	59.0
Debary	4		46.0	59.0	100.0	46.0	59.0
Debary	5		45.0	58.0	100.0	45.0	58.0
Debary	6		46.0	59.0	100.0	46.0	59.0
Debary	7		74.0	93.0	100.0	74.0	93.0
Debary	8		75.0	94.0	100.0	75.0	94.0
Debary	9		76.0	94.0	100.0	76.0	94.0
Duette Solar Power Plant	PV1		74.5	74.5	100.0	74.5	74.5
Epcot Solar	PV1		4.9	4.9	100.0	4.9	4.9
Falmouth Renewable Energy Center	PV1		74.9	74.9	100.0	74.9	74.9
Fort Green Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Hamilton Solar Plant	PV1		74.9	74.9	100.0	74.9	74.9
Hardeetown Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
High Springs Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Hildreth Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Hines Energy Complex	CC1		501.0	521.0	100.0	501.0	521.0
Hines Energy Complex	CC2		532.0	549.0	100.0	532.0	549.0
Hines Energy Complex	CC3		523.0	535.0	100.0	523.0	535.0
Hines Energy Complex	CC4		544.0	544.0	100.0	544.0	544.0
Intercession City	P1		45.0	61.0	100.0	45.0	61.0

Plant Name	Unit	Start Year	Capacity (MW)		Ownership Share (%)	Inputted Capacity (MW)	
			Summer	Winter		Summer	Winter
Intercession City	P10		74.0	86.0	100.0	74.0	86.0
Intercession City	P11		140.0	161.0	100.0	140.0	161.0
Intercession City	P12		73.0	89.0	100.0	73.0	89.0
Intercession City	P13		73.0	91.0	100.0	73.0	91.0
Intercession City	P14		73.0	90.0	100.0	73.0	90.0
Intercession City	P2		46.0	60.0	100.0	46.0	60.0
Intercession City	P3		46.0	61.0	100.0	46.0	61.0
Intercession City	P4		46.0	62.0	100.0	46.0	62.0
Intercession City	P5		45.0	59.0	100.0	45.0	59.0
Intercession City	P6		47.0	60.0	100.0	47.0	60.0
Intercession City	P7		78.0	90.0	100.0	78.0	90.0
Intercession City	P8		77.0	88.0	100.0	77.0	88.0
Intercession City	P9		77.0	88.0	100.0	77.0	88.0
Jennings Energy Storage Project	BA1		5.5	5.5	100.0	5.5	5.5
John Hopkins Middle School	BA1		2.5	2.5	100.0	2.5	2.5
John Hopkins Middle School	PV1		0.8	0.8	100.0	0.8	0.8
Lake Placid Solar Power Plant	BA1		17.3	17.3	100.0	17.3	17.3
Lake Placid Solar Power Plant	PV1		45.0	45.0	100.0	45.0	45.0
Micanopy Energy Storage Facility	BA1		8.3	8.3	100.0	8.3	8.3
Mule Creek Renewable Energy Center	PV1		74.9	74.9	100.0	74.9	74.9
Osceola Solar Facility	PV1		3.8	3.8	100.0	3.8	3.8
P L Bartow	CC		1,142.0	1,259.0	100.0	1,142.0	1,259.0
P L Bartow	P1		41.0	50.0	100.0	41.0	50.0
P L Bartow	P2		41.0	53.0	100.0	41.0	53.0
P L Bartow	P3		41.0	51.0	100.0	41.0	51.0
P L Bartow	P4		45.0	58.0	100.0	45.0	58.0
Perry Solar Facility	PV1		5.1	5.1	100.0	5.1	5.1
Sandy Creek Solar	PV1		74.9	74.9	100.0	74.9	74.9
Santa Fe Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Suwannee	P1		48.0	65.0	100.0	48.0	65.0
Suwannee	P2		48.0	64.0	100.0	48.0	64.0
Suwannee	P3		49.0	65.0	100.0	49.0	65.0
Suwannee	PV 1		8.8	8.8	100.0	8.8	8.8

			Capacity (MW)			Inputted Capacity (MW)	
Plant Name	**Unit**	**Start Year**	**Summer**	**Winter**	**Ownership Share (%)**	**Summer**	**Winter**
Tiger Bay	CS1		199.0	230.0	100.0	199.0	230.0
Trenton Energy Storage Project	BA1		11.0	11.0	100.0	11.0	11.0
Trenton Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Twin Rivers Solar Power Plant	PV1		74.9	74.9	100.0	74.9	74.9
Univ of Florida	P1		44.0	50.0	100.0	44.0	50.0
Winquepin Renewable Energy Center	PV1		74.9	74.9	100.0	74.9	74.9
Duke Net Generation in FPC						**11,058.2**	**12,030.2**
TEC							
Osprey Energy Center	CC		616.0	611.0	100.0	616.0	611.0
Duke Net Generation in TEC						**616.0**	**611.0**

Sources: EIA-860M, April 2025; Secretariat DPT Model.

NextEra Sales

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Decatur Solar Energy Center LLC	2024	Southern Co Services Inc	Georgia Power Co	Energy	$/MWH	Unit Power Sale	Long Term	161,838	26	4,245,793
FRP Columbia County Solar LLC	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Unit Power Sale	Long Term	38,537	29	1,120,659
FRP Gadsden County Solar LLC	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Unit Power Sale	Long Term	24,828	29	725,730
FRP Gilchrist County Solar LLC	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Unit Power Sale	Long Term	22,461	30	668,453
FRP Tupelo Solar LLC	2024	Florida Power & Light	Seminole Electric Coop Inc	Energy	$/MWH	Unit Power Sale	Long Term	30,322	29	885,000
Florida Power & Light Co	2023	Duke Energy Florida Inc	Duke Energy Florida	Energy	$/MWH	Non-firm	Short Term	42,125	56	2,338,718
Florida Power & Light Co	2023	Duke Energy Florida Inc	Duke Energy Florida	Exchange	$/MW	Firm	Short Term	142	0	0
Florida Power & Light Co	2023	Duke Energy Florida Inc	Duke Energy Florida	Exchange	$/MWH	Firm	Short Term	2,298	0	0
Florida Power & Light Co	2023	Duke Energy Florida Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	133,581	39	5,273,842
Florida Power & Light Co	2023	Duke Energy Florida Inc	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	800	24	19,200
Florida Power & Light Co	2023	Duke Energy Florida Inc	Reedy Creek Improvement District	Energy	$/MWH	Non-firm	Short Term	2,091	24	50,576
Florida Power & Light Co	2023	Florida Municipal Power Pool	Duke Energy Florida	Spinning Reserve	$/MW-DAY	Firm	Short Term	720	285	205,200
Florida Power & Light Co	2023	Florida Municipal Power Pool	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	7,834	100	781,833
Florida Power & Light Co	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Exchange	$/MW	Firm	Short Term	284	0	0
Florida Power & Light Co	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Exchange	$/MWH	Firm	Short Term	585	0	0
Florida Power & Light Co	2023	Florida Municipal Power Pool	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	293,555	37	10,925,495
Florida Power & Light Co	2023	Florida Municipal Power Pool	Seminole Electric Coop Inc	Spinning Reserve	$/KW-MO	Firm	Short Term	780,000	3	1,950,000
Florida Power & Light Co	2023	Florida Municipal Power Pool	Seminole Electric Coop Inc	Spinning Reserve	$/MW-DAY	Firm	Short Term	5,078	113	571,275
Florida Power & Light Co	2023	Florida Municipal Power Pool	Tallahassee FL (City of)	Spinning Reserve	$/MW-DAY	Firm	Short Term	141	285	40,185
Florida Power & Light Co	2023	Florida Municipal Power Pool	Tampa Electric Co	Spinning Reserve	$/MW-DAY	Firm	Short Term	675	286	193,050
Florida Power & Light Co	2023	Florida Power & Light	Alachua FL (City of)	Capacity	$/KW-MO	Firm	Long Term	205,360	5	924,121
Florida Power & Light Co	2023	Florida Power & Light	Alachua FL (City of)	Energy	$/MWH	Firm	Long Term	101,846	1	101,846
Florida Power & Light Co	2023	Florida Power & Light	Alachua FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	101,842	24	2,431,613
Florida Power & Light Co	2023	Florida Power & Light	Blountstown FL (City of)	Capacity	$/KW-MO	Firm	Long Term	74,368	5	334,656
Florida Power & Light Co	2023	Florida Power & Light	Blountstown FL (City of)	Energy	$/MWH	Firm	Long Term	32,814	1	41,017
Florida Power & Light Co	2023	Florida Power & Light	Blountstown FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	32,814	24	775,460
Florida Power & Light Co	2023	Florida Power & Light	Energy Authority Inc (The)	Energy	$/MWH	Firm	Long Term	103,085	37	3,772,911
Florida Power & Light Co	2023	Florida Power & Light	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	912,918	28	25,793,824
Florida Power & Light Co	2023	Florida Power & Light	Energy Authority Inc (The)	Other	$/MWH	Firm	Long Term	275,915	3	827,745
Florida Power & Light Co	2023	Florida Power & Light	Florida Keys Electric Coop Association Inc	Capacity	$/KW-MO	Firm	Long Term	1,700,870	18	30,122,408
Florida Power & Light Co	2023	Florida Power & Light	Florida Keys Electric Coop Association Inc	Customer Charge	FLAT RATE	Firm	Long Term	12	5,000	60,000
Florida Power & Light Co	2023	Florida Power & Light	Florida Keys Electric Coop Association Inc	Energy	$/MWH	Firm	Long Term	845,913	2	2,042,879
Florida Power & Light Co	2023	Florida Power & Light	Florida Keys Electric Coop Association Inc	Fuel Charge	$/MWH	Firm	Long Term	845,913	24	19,996,658
Florida Power & Light Co	2023	Florida Power & Light	Florida Municipal Power Agency	Exchange	$/KWH	Unit Power Sale	Long Term	379,884	0	1,777
Florida Power & Light Co	2023	Florida Power & Light	Florida Public Utilities Co	Capacity	$/KW-MO	Firm	Long Term	1,392,849	7	9,465,178
Florida Power & Light Co	2023	Florida Power & Light	Florida Public Utilities Co	Customer Charge	FLAT RATE	Firm	Long Term	24	2,000	48,000
Florida Power & Light Co	2023	Florida Power & Light	Florida Public Utilities Co	Energy	$/MWH	Firm	Long Term	474,899	2	1,087,889
Florida Power & Light Co	2023	Florida Power & Light	Florida Public Utilities Co	Energy	$/MWH	Non-firm	Short Term	73,564	27	1,972,184
Florida Power & Light Co	2023	Florida Power & Light	Florida Public Utilities Co	Fuel Charge	$/MWH	Firm	Long Term	474,899	30	14,305,822
Florida Power & Light Co	2023	Florida Power & Light	Homestead FL (City of)	Capacity	$/KW-MO	Firm	Long Term	1,032,000	5	5,588,280
Florida Power & Light Co	2023	Florida Power & Light	Homestead FL (City of)	Energy	$/MWH	Firm	Long Term	315,008	1	433,136
Florida Power & Light Co	2023	Florida Power & Light	Homestead FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	315,008	24	7,526,145
Florida Power & Light Co	2023	Florida Power & Light	JEA	Capacity	$/KW-MO	Firm	Long Term	2,400,000	7	16,800,000
Florida Power & Light Co	2023	Florida Power & Light	JEA	Energy	$/MWH	Firm	Long Term	1,455,108	2	2,182,662
Florida Power & Light Co	2023	Florida Power & Light	JEA	Fuel Charge	$/MWH	Firm	Long Term	1,455,108	24	34,775,571
Florida Power & Light Co	2023	Florida Power & Light	Lee County Electric Coop Inc	Capacity	$/KW-MO	Firm	Long Term	10,495,013	19	195,092,289
Florida Power & Light Co	2023	Florida Power & Light	Lee County Electric Coop Inc	Customer Charge	FLAT RATE	Firm	Long Term	12	10,000	120,000
Florida Power & Light Co	2023	Florida Power & Light	Lee County Electric Coop Inc	Energy	$/MWH	Firm	Long Term	4,726,210	2	11,752,508
Florida Power & Light Co	2023	Florida Power & Light	Lee County Electric Coop Inc	Fuel Charge	$/MWH	Firm	Long Term	4,726,210	24	111,779,161
Florida Power & Light Co	2023	Florida Power & Light	Moore Haven FL (City of)	Capacity	$/KW-MO	Firm	Long Term	40,965	9	360,489
Florida Power & Light Co	2023	Florida Power & Light	Moore Haven FL (City of)	Customer Charge	FLAT RATE	Firm	Long Term	12	750	9,000
Florida Power & Light Co	2023	Florida Power & Light	Moore Haven FL (City of)	Energy	$/MWH	Firm	Long Term	16,651	4	62,441
Florida Power & Light Co	2023	Florida Power & Light	Moore Haven FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	16,651	24	393,932
Florida Power & Light Co	2023	Florida Power & Light	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	30,987	28	880,709
Florida Power & Light Co	2023	Florida Power & Light	Orlando Utilities Commission	Exchange	$/KWH	Unit Power Sale	Long Term	262,696	0	1,373
Florida Power & Light Co	2023	Florida Power & Light	Quincy Utility Dept	Capacity	$/KW-MO	Firm	Long Term	201,000	7	1,457,250
Florida Power & Light Co	2023	Florida Power & Light	Quincy Utility Dept	Customer Charge	FLAT RATE	Firm	Long Term	12	2,000	24,000
Florida Power & Light Co	2023	Florida Power & Light	Quincy Utility Dept	Energy	$/MWH	Firm	Long Term	96,318	3	288,954
Florida Power & Light Co	2023	Florida Power & Light	Quincy Utility Dept	Fuel Charge	$/MWH	Firm	Long Term	96,318	24	2,301,900

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Capacity	$/KW-MO	Firm	Long Term	1,015,000	5	4,912,600
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Customer Charge	FLAT RATE	Firm	Long Term	12	2,500	30,000
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Energy	$/MWH	Firm	Long Term	397,627	19	7,374,570
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Energy	$/MWH	Non-firm	Short Term	3,790	36	138,138
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Fuel Charge	$/MWH	Firm	Long Term	389,880	24	9,224,359
Florida Power & Light Co	2023	Florida Power & Light	Utilities Commission New Smyrna Beach	Other	$/MW-MO	Firm	Long Term	169	1,375	232,824
Florida Power & Light Co	2023	Florida Power & Light	Wauchula FL (City of)	Capacity	$/KW-MO	Firm	Long Term	143,082	7	1,001,574
Florida Power & Light Co	2023	Florida Power & Light	Wauchula FL (City of)	Customer Charge	FLAT RATE	Firm	Long Term	12	1,000	12,000
Florida Power & Light Co	2023	Florida Power & Light	Wauchula FL (City of)	Energy	$/MWH	Firm	Long Term	65,195	3	179,285
Florida Power & Light Co	2023	Florida Power & Light	Wauchula FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	65,195	25	1,627,336
Florida Power & Light Co	2023	Florida Power & Light	Wauchula FL (City of)	Other	FLAT RATE	Firm	Long Term	12	3,671	44,050
Florida Power & Light Co	2023	Gainesville Regional Utilities	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	23,284	36	839,599
Florida Power & Light Co	2023	Gainesville Regional Utilities	Gainesville Regional Utilities	Exchange	$/MWH	Firm	Short Term	105	0	0
Florida Power & Light Co	2023	Homestead (City of)	Homestead FL (City of)	Energy	$/MWH	Non-firm	Short Term	45	33	1,485
Florida Power & Light Co	2023	JEA	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	375	43	16,219
Florida Power & Light Co	2023	JEA	Energy Authority Inc (The)	Energy	$/MWH	Firm	Long Term	172,830	37	6,325,578
Florida Power & Light Co	2023	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	138,332	34	4,687,327
Florida Power & Light Co	2023	JEA	JEA	Exchange	$/MW	Firm	Short Term	151	0	0
Florida Power & Light Co	2023	JEA	JEA	Exchange	$/MWH	Firm	Short Term	232	0	0
Florida Power & Light Co	2023	JEA	Macquarie Energy LLC	Energy	$/MWH	Firm	Short Term	144,432	72	10,399,104
Florida Power & Light Co	2023	JEA	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	100	42	4,200
Florida Power & Light Co	2023	JEA	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	5,934	38	223,514
Florida Power & Light Co	2023	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Exchange	$/MW	Firm	Short Term	305	0	0
Florida Power & Light Co	2023	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	1,751	0	0
Florida Power & Light Co	2023	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	563,216	35	19,655,833
Florida Power & Light Co	2023	Southern Co Services Inc	EDF Trading North America LLC	Energy	$/MWH	Non-firm	Short Term	955	36	34,141
Florida Power & Light Co	2023	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	17,010	30	513,731
Florida Power & Light Co	2023	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Firm	Short Term	33,593	52	1,730,040
Florida Power & Light Co	2023	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	49,553	42	2,063,529
Florida Power & Light Co	2023	Southern Co Services Inc	Mercuria Energy America LLC	Energy	$/MWH	Non-firm	Short Term	156,943	38	5,964,619
Florida Power & Light Co	2023	Southern Co Services Inc	Morgan Stanley Capital Group Inc	Energy	$/MWH	Non-firm	Short Term	112,137	35	3,943,895
Florida Power & Light Co	2023	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	709	63	44,809
Florida Power & Light Co	2023	Southern Co Services Inc	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	34,263	31	1,073,728
Florida Power & Light Co	2023	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	26,397	42	1,117,527
Florida Power & Light Co	2023	Southern Co Services Inc	Tennessee Valley Authority	Energy	$/MWH	Non-firm	Short Term	74,400	110	8,184,000
Florida Power & Light Co	2023	Tallahassee FL (City of)	Tallahassee FL (City of)	Exchange	$/MWH	Firm	Short Term	139	0	0
Florida Power & Light Co	2023	Tampa Electric Co	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	194	115	22,310
Florida Power & Light Co	2023	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	450,364	47	21,079,549
Florida Power & Light Co	2023	Tampa Electric Co	Tampa Electric Co	Exchange	$/MW	Firm	Short Term	336	0	0
Florida Power & Light Co	2023	Tampa Electric Co	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	639	0	0
Florida Power & Light Co	2024	Duke Energy Florida Inc	Duke Energy Florida	Energy	$/MWH	Non-firm	Short Term	91,357	72	6,569,728
Florida Power & Light Co	2024	Duke Energy Florida Inc	Duke Energy Florida	Exchange	$/MWH	Firm	Short Term	529	0	0
Florida Power & Light Co	2024	Duke Energy Florida Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	19,160	54	1,029,166
Florida Power & Light Co	2024	Duke Energy Florida Inc	Florida Municipal Power Agency	Exchange	$/MWH	Firm	Short Term	19	0	0
Florida Power & Light Co	2024	Duke Energy Florida Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	7,101	135	958,635
Florida Power & Light Co	2024	Duke Energy Florida Inc	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	50	40	2,000
Florida Power & Light Co	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	42	0	0
Florida Power & Light Co	2024	Duke Energy Florida Inc	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	88	0	0
Florida Power & Light Co	2024	Florida Municipal Power Pool	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	8,322	50	414,587
Florida Power & Light Co	2024	Florida Municipal Power Pool	Florida Municipal Power Agency	Exchange	$/MWH	Firm	Short Term	737	0	0
Florida Power & Light Co	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	63,260	42	2,659,225
Florida Power & Light Co	2024	Florida Municipal Power Pool	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	56	0	0
Florida Power & Light Co	2024	Florida Municipal Power Pool	Tampa Electric Co	Capacity	$/MW-DAY	Non-firm	Long Term	300	149	44,700
Florida Power & Light Co	2024	Florida Municipal Power Pool	Tampa Electric Co	Capacity	$/MW-MO	Firm	Short Term	184	4,500	827,550
Florida Power & Light Co	2024	Florida Municipal Power Pool	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	70	0	0
Florida Power & Light Co	2024	Florida Power & Light	Alachua FL (City of)	Capacity	$/KW-MO	Firm	Long Term	208,316	5	937,423
Florida Power & Light Co	2024	Florida Power & Light	Alachua FL (City of)	Energy	$/MWH	Firm	Long Term	100,607	1	100,607
Florida Power & Light Co	2024	Florida Power & Light	Alachua FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	100,607	23	2,283,782
Florida Power & Light Co	2024	Florida Power & Light	Bartow FL (City of)	Capacity	$/KW-MO	Firm	Long Term	691,567	3	2,247,593
Florida Power & Light Co	2024	Florida Power & Light	Bartow FL (City of)	Energy	$/MWH	Firm	Long Term	325,115	1	325,115
Florida Power & Light Co	2024	Florida Power & Light	Bartow FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	325,115	19	6,128,388

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Florida Power & Light Co	2024	Florida Power & Light	Blountstown FL (City of)	Capacity	$/KW-MO	Firm	Long Term	77,519	5	348,836
Florida Power & Light Co	2024	Florida Power & Light	Blountstown FL (City of)	Energy	$/MWH	Firm	Long Term	34,568	1	43,210
Florida Power & Light Co	2024	Florida Power & Light	Blountstown FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	34,568	22	749,708
Florida Power & Light Co	2024	Florida Power & Light	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	35	100	3,500
Florida Power & Light Co	2024	Florida Power & Light	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	383,018	28	10,586,878
Florida Power & Light Co	2024	Florida Power & Light	Energy Authority Inc (The)	Other	$/MWH	Firm	Long Term	374,936	3	1,124,808
Florida Power & Light Co	2024	Florida Power & Light	Florida Keys Electric Coop Association Inc	Capacity	$/KW-MO	Firm	Long Term	1,695,581	18	30,249,165
Florida Power & Light Co	2024	Florida Power & Light	Florida Keys Electric Coop Association Inc	Customer Charge	FLAT RATE	Firm	Long Term	12	5,000	60,000
Florida Power & Light Co	2024	Florida Power & Light	Florida Keys Electric Coop Association Inc	Energy	$/MWH	Firm	Long Term	844,469	3	2,128,062
Florida Power & Light Co	2024	Florida Power & Light	Florida Keys Electric Coop Association Inc	Fuel Charge	$/MWH	Firm	Long Term	844,469	22	18,305,348
Florida Power & Light Co	2024	Florida Power & Light	Florida Municipal Power Agency	Exchange	$/KWH	Unit Power Sale	Long Term	335,426	0	1,683
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Capacity	$/KW-MO	Firm	Long Term	1,463,071	6	9,406,579
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Customer Charge	FLAT RATE	Firm	Long Term	18	2,000	36,000
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Energy	$/MWH	Firm	Long Term	506,452	2	1,164,761
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Energy	$/MWH	Non-firm	Short Term	81,334	28	2,243,144
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Fuel Charge	$/MWH	Firm	Long Term	507,014	29	14,687,840
Florida Power & Light Co	2024	Florida Power & Light	Florida Public Utilities Co	Other	FLAT RATE	Firm	Long Term	-1	17	-17
Florida Power & Light Co	2024	Florida Power & Light	Homestead FL (City of)	Capacity	$/KW-MO	Firm	Long Term	1,032,000	5	5,608,920
Florida Power & Light Co	2024	Florida Power & Light	Homestead FL (City of)	Energy	$/MWH	Firm	Long Term	340,158	1	467,717
Florida Power & Light Co	2024	Florida Power & Light	Homestead FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	340,158	23	7,710,841
Florida Power & Light Co	2024	Florida Power & Light	JEA	Capacity	$/KW-MO	Firm	Long Term	2,400,000	7	16,800,000
Florida Power & Light Co	2024	Florida Power & Light	JEA	Energy	$/MWH	Firm	Long Term	1,442,302	2	2,163,453
Florida Power & Light Co	2024	Florida Power & Light	JEA	Fuel Charge	$/MWH	Firm	Long Term	1,442,302	23	32,740,157
Florida Power & Light Co	2024	Florida Power & Light	Lee County Electric Coop Inc	Capacity	$/KW-MO	Firm	Long Term	10,495,758	19	200,325,845
Florida Power & Light Co	2024	Florida Power & Light	Lee County Electric Coop Inc	Customer Charge	FLAT RATE	Firm	Long Term	12	10,000	120,000
Florida Power & Light Co	2024	Florida Power & Light	Lee County Electric Coop Inc	Energy	$/MWH	Firm	Long Term	4,833,005	3	12,340,274
Florida Power & Light Co	2024	Florida Power & Light	Lee County Electric Coop Inc	Fuel Charge	$/MWH	Firm	Long Term	4,833,005	22	106,853,618
Florida Power & Light Co	2024	Florida Power & Light	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	115,706	39	4,526,575
Florida Power & Light Co	2024	Florida Power & Light	Moore Haven FL (City of)	Capacity	$/KW-MO	Firm	Long Term	40,360	9	363,243
Florida Power & Light Co	2024	Florida Power & Light	Moore Haven FL (City of)	Customer Charge	FLAT RATE	Firm	Long Term	12	750	9,000
Florida Power & Light Co	2024	Florida Power & Light	Moore Haven FL (City of)	Energy	$/MWH	Firm	Long Term	17,394	4	69,577
Florida Power & Light Co	2024	Florida Power & Light	Moore Haven FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	17,394	22	384,642
Florida Power & Light Co	2024	Florida Power & Light	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	218,993	29	6,408,143
Florida Power & Light Co	2024	Florida Power & Light	Orlando Utilities Commission	Exchange	$/KWH	Unit Power Sale	Long Term	231,953	0	1,105
Florida Power & Light Co	2024	Florida Power & Light	Quincy Utility Dept	Capacity	$/KW-MO	Firm	Long Term	182,000	7	1,274,000
Florida Power & Light Co	2024	Florida Power & Light	Quincy Utility Dept	Customer Charge	FLAT RATE	Firm	Long Term	12	3,000	36,000
Florida Power & Light Co	2024	Florida Power & Light	Quincy Utility Dept	Energy	$/MWH	Firm	Long Term	86,540	3	237,985
Florida Power & Light Co	2024	Florida Power & Light	Quincy Utility Dept	Fuel Charge	$/MWH	Firm	Long Term	86,540	23	1,964,452
Florida Power & Light Co	2024	Florida Power & Light	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	116,300	39	4,583,277
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Capacity	$/KW-MO	Firm	Long Term	1,075,000	5	5,203,000
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Customer Charge	FLAT RATE	Firm	Long Term	12	2,500	30,000
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Energy	$/MWH	Firm	Long Term	375,176	18	6,884,129
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Energy	$/MWH	Non-firm	Long Term	52,371	41	2,147,211
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Energy	$/MWH	Non-firm	Short Term	1,917	35	67,795
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Fuel Charge	$/MWH	Firm	Long Term	367,753	22	8,135,961
Florida Power & Light Co	2024	Florida Power & Light	Utilities Commission New Smyrna Beach	Other	$/MW-MO	Firm	Long Term	261	1,500	392,164
Florida Power & Light Co	2024	Florida Power & Light	Wauchula FL (City of)	Capacity	$/KW-MO	Firm	Long Term	142,506	3	463,145
Florida Power & Light Co	2024	Florida Power & Light	Wauchula FL (City of)	Energy	$/MWH	Firm	Long Term	66,515	1	66,515
Florida Power & Light Co	2024	Florida Power & Light	Wauchula FL (City of)	Fuel Charge	$/MWH	Firm	Long Term	66,515	19	1,253,794
Florida Power & Light Co	2024	Florida Power & Light	Wauchula FL (City of)	Other	FLAT RATE	Firm	Long Term	10	2,036	20,356
Florida Power & Light Co	2024	Gainesville Regional Utilities	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	2,345	39	90,434
Florida Power & Light Co	2024	Gainesville Regional Utilities	Gainesville Regional Utilities	Exchange	$/MWH	Firm	Short Term	66	0	0
Florida Power & Light Co	2024	Gainesville Regional Utilities	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	21	0	0
Florida Power & Light Co	2024	Gainesville Regional Utilities	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	11	0	0
Florida Power & Light Co	2024	JEA	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	528	80	42,240
Florida Power & Light Co	2024	JEA	Energy Authority Inc (The)	Energy	$/MWH	Firm	Long Term	374,936	37	13,722,658
Florida Power & Light Co	2024	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	188,042	44	8,353,961
Florida Power & Light Co	2024	JEA	JEA	Exchange	$/MWH	Firm	Short Term	255	0	0
Florida Power & Light Co	2024	JEA	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	12,761	56	717,806
Florida Power & Light Co	2024	JEA	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	12,437	44	549,301
Florida Power & Light Co	2024	JEA	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	18	0	0

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Florida Power & Light Co	2024	Seminole Electric Coop Inc	Florida Municipal Power Agency	Exchange	$/MWH	Firm	Short Term	60	0	0
Florida Power & Light Co	2024	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	520	0	0
Florida Power & Light Co	2024	Seminole Electric Coop Inc	Tallahassee FL (City of)	Exchange	$/MWH	Firm	Short Term	21	0	0
Florida Power & Light Co	2024	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	204,769	40	8,220,378
Florida Power & Light Co	2024	Southern Co Services Inc	EDF Trading North America LLC	Energy	$/MWH	Non-firm	Short Term	14,638	34	491,852
Florida Power & Light Co	2024	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	8,290	39	324,897
Florida Power & Light Co	2024	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	308,119	62	19,144,461
Florida Power & Light Co	2024	Southern Co Services Inc	Mercuria Energy America LLC	Energy	$/MWH	Non-firm	Short Term	152,849	39	5,941,419
Florida Power & Light Co	2024	Southern Co Services Inc	Morgan Stanley Capital Group Inc	Energy	$/MWH	Non-firm	Short Term	115,586	36	4,218,039
Florida Power & Light Co	2024	Southern Co Services Inc	Municipal Electric Authority of Georgia	Energy	$/MWH	Non-firm	Short Term	212	38	7,985
Florida Power & Light Co	2024	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	314	28	8,635
Florida Power & Light Co	2024	Southern Co Services Inc	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	88,516	45	4,018,258
Florida Power & Light Co	2024	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	11,715	52	614,239
Florida Power & Light Co	2024	Tallahassee FL (City of)	Duke Energy Florida	Exchange	$/MWH	Firm	Short Term	54	0	0
Florida Power & Light Co	2024	Tallahassee FL (City of)	Florida Municipal Power Agency	Exchange	$/MWH	Firm	Short Term	25	0	0
Florida Power & Light Co	2024	Tallahassee FL (City of)	Tallahassee FL (City of)	Exchange	$/MWH	Firm	Short Term	413	0	0
Florida Power & Light Co	2024	Tallahassee FL (City of)	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	65	0	0
Florida Power & Light Co	2024	Tampa Electric Co	Duke Energy Florida	Energy	$/MWH	Non-firm	Short Term	7,700	64	492,800
Florida Power & Light Co	2024	Tampa Electric Co	Duke Energy Florida	Exchange	$/MWH	Firm	Short Term	131	0	0
Florida Power & Light Co	2024	Tampa Electric Co	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	50	0	0
Florida Power & Light Co	2024	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Long Term	376	236	88,665
Florida Power & Light Co	2024	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	322,874	56	17,975,757
Florida Power & Light Co	2024	Tampa Electric Co	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	923	0	0
Harmony Florida Solar II LLC	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Energy	$/MWH	Unit Power Sale	Long Term	12,946	30	382,421
Live Oak Solar LLC	2023	Southern Co Services Inc	Georgia Power Co	Energy	$/MWH	Unit Power Sale	Long Term	93,469	54	5,031,450
Live Oak Solar LLC	2024	Southern Co Services Inc	Georgia Power Co	Energy	$/MWH	Unit Power Sale	Long Term	94,090	50	4,695,087
Live Oak Solar LLC	2024	Southern Co Services Inc	Georgia Power Co	Other	FLAT RATE	Unit Power Sale	Long Term	1	-26	-26
NextEra Energy Power Marketing LLC	2023	Southern Co Services Inc	Cimarron Wind Energy LLC	Energy	$/MWH	Firm	Short Term	21,840	32	700,908
NextEra Energy Power Marketing LLC	2024	Southern Co Services Inc	Cimarron Wind Energy LLC	Energy	$/MWH	Firm	Long Term	1,568	23	36,064
NextEra River Bend Solar LLC	2023	Southern Co Services Inc	Tennessee Valley Authority	Energy	$/MWH	Unit Power Sale	Long Term	153,229	55	8,356,837
NextEra River Bend Solar LLC	2024	Southern Co Services Inc	Tennessee Valley Authority	Energy	$/MWH	Unit Power Sale	Long Term	149,307	57	8,484,118
Oleander Power Project LP	2023	Florida Power & Light	Florida Municipal Power Agency	Capacity	$/KW-MO	Firm	Long Term	1,911,082	5	8,676,312
Oleander Power Project LP	2023	Florida Power & Light	Florida Municipal Power Agency	Other	FLAT RATE	Firm	Long Term	64	14,172	907,010
Oleander Power Project LP	2023	Florida Power & Light	Florida Municipal Power Agency	Tolling Energy	FLAT RATE	Firm	Long Term	39,159	3	108,470
Oleander Power Project LP	2023	Florida Power & Light	Seminole Electric Coop Inc	Capacity	$/KW-MO	Firm	Long Term	6,112,800	1	8,557,920
Oleander Power Project LP	2023	Florida Power & Light	Seminole Electric Coop Inc	Other	FLAT RATE	Firm	Long Term	242	14,240	3,446,114
Oleander Power Project LP	2023	Florida Power & Light	Seminole Electric Coop Inc	Tolling Energy	FLAT RATE	Firm	Long Term	1,646	884	1,455,981
Oleander Power Project LP	2024	Florida Power & Light	Florida Municipal Power Agency	Capacity	$/KW-MO	Firm	Long Term	1,904,976	5	8,648,591
Oleander Power Project LP	2024	Florida Power & Light	Florida Municipal Power Agency	Other	FLAT RATE	Firm	Long Term	72	8,551	615,683
Oleander Power Project LP	2024	Florida Power & Light	Florida Municipal Power Agency	Tolling Energy	FLAT RATE	Firm	Long Term	45,678	2,783	127,130,210
Oleander Power Project LP	2024	Florida Power & Light	Seminole Electric Coop Inc	Capacity	$/KW-MO	Firm	Long Term	6,112,800	1	8,557,920
Oleander Power Project LP	2024	Florida Power & Light	Seminole Electric Coop Inc	Other	FLAT RATE	Firm	Long Term	263	22,829	6,004,119
Oleander Power Project LP	2024	Florida Power & Light	Seminole Electric Coop Inc	Tolling Energy	FLAT RATE	Firm	Long Term	2,151	758	1,630,776
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Capacity	$/KW-MO	Firm	Long Term	786,482	9	6,997,153
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Other	FLAT RATE	Firm	Long Term	52	22,004	1,144,234
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Tolling Energy	$/MWH	Firm	Long Term	273,412	1	284,348
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Florida Municipal Power Agency	Tolling Energy	FLAT RATE	Firm	Long Term	9,326	160	1,496,086
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Orlando Utilities Commission	Capacity	$/KW-MO	Firm	Long Term	4,171,476	3	14,083,946
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Orlando Utilities Commission	Other	FLAT RATE	Firm	Long Term	48	175,242	8,411,621
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Orlando Utilities Commission	Tolling Energy	$/MWH	Firm	Long Term	1,494,228	1	2,208,467
Stanton Clean Energy LLC	2023	Florida Municipal Power Pool	Orlando Utilities Commission	Tolling Energy	FLAT RATE	Firm	Long Term	4,663	1,283	5,984,354
Stanton Clean Energy LLC	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Capacity	$/KW-MO	Firm	Long Term	4,785,872	4	16,750,552
Stanton Clean Energy LLC	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Other	FLAT RATE	Firm	Long Term	49	185,325	9,080,946
Stanton Clean Energy LLC	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Tolling Energy	$/MWH	Firm	Long Term	1,792,025	3	4,569,665
Wadley Solar LLC	2024	Southern Co Services Inc	Georgia Power Co	Energy	$/MWH	Unit Power Sale	Long Term	268,984	28	7,483,522
Washington County Solar LLC	2024	Southern Co Services Inc	Georgia Power Co	Energy	$/MWH	Unit Power Sale	Long Term	175,669	28	4,879,845

Source: Hitachi Energy, EQR Sales

Duke Energy Sales

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Duke Energy Carolinas	2023	Gainesville Regional Utilities	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	488	28	13,577
Duke Energy Carolinas	2023	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	11,734	31	361,823
Duke Energy Carolinas	2023	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	40	28	1,120
Duke Energy Carolinas	2023	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	9,556	29	276,336
Duke Energy Carolinas	2023	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	11,420	43	485,751
Duke Energy Carolinas	2023	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	73,056	29	2,119,965
Duke Energy Carolinas	2023	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	182	23	4,245
Duke Energy Carolinas	2024	Gainesville Regional Utilities	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	2,848	21	59,994
Duke Energy Carolinas	2024	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	10,878	28	308,743
Duke Energy Carolinas	2024	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	800	42	33,400
Duke Energy Carolinas	2024	Southern Co Services Inc	EDF Trading North America LLC	Energy	$/MWH	Non-firm	Short Term	30	53	1,590
Duke Energy Carolinas	2024	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	4,475	24	109,129
Duke Energy Carolinas	2024	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	540	75	40,500
Duke Energy Carolinas	2024	Southern Co Services Inc	Morgan Stanley Capital Group Inc	Energy	$/MWH	Non-firm	Short Term	300	32	9,600
Duke Energy Carolinas	2024	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	9,610	35	335,924
Duke Energy Carolinas	2024	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	32,044	21	685,472
Duke Energy Carolinas	2024	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	284	19	5,389
Duke Energy Florida	2023	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Capacity	$/MW-MO	Firm	Long Term	457	7,000	3,199,000
Duke Energy Florida	2023	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Energy	$/MWH	Firm	Long Term	140,254	30	4,153,507
Duke Energy Florida	2023	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Energy	$/MWH	Non-firm	Short Term	45,380	23	1,029,407
Duke Energy Florida	2023	Duke Energy Florida Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	105,330	32	3,344,029
Duke Energy Florida	2023	Duke Energy Florida Inc	Florida Municipal Power Agency	Energy	$/MWH	Non-firm	Short Term	21,150	26	558,645
Duke Energy Florida	2023	Duke Energy Florida Inc	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	9,425	33	309,850
Duke Energy Florida	2023	Duke Energy Florida Inc	Reedy Creek Improvement District	Capacity	$/MW-MO	Firm	Long Term	217	7,000	1,519,000
Duke Energy Florida	2023	Duke Energy Florida Inc	Reedy Creek Improvement District	Energy	$/MWH	Firm	Long Term	53,674	31	1,649,720
Duke Energy Florida	2023	Duke Energy Florida Inc	Reedy Creek Improvement District	Energy	$/MWH	Non-firm	Short Term	10,960	23	252,140
Duke Energy Florida	2023	Duke Energy Florida Inc	Seminole Electric Coop Inc	Capacity	$/MW-MO	Firm	Long Term	0	7,740	658
Duke Energy Florida	2023	Duke Energy Florida Inc	Seminole Electric Coop Inc	Customer Charge	FLAT RATE	Firm	Long Term	9	264	2,376
Duke Energy Florida	2023	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Firm	Long Term	97	67	6,513
Duke Energy Florida	2023	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Non-firm	Short Term	550	58	31,900
Duke Energy Florida	2023	Duke Energy Florida Inc	Southeastern Power Administration	Capacity	$/MW-MO	Firm	Long Term	120	2,550	305,544
Duke Energy Florida	2023	Duke Energy Florida Inc	Southeastern Power Administration	Energy	$/MWH	Firm	Long Term	16,219	47	754,473
Duke Energy Florida	2023	Duke Energy Florida Inc	Southeastern Power Administration	Other	$/MW-MO	Firm	Long Term	136,459	1	155,830
Duke Energy Florida	2023	Duke Energy Florida Inc	Southeastern Power Administration	Regulation & Frequency Response	FLAT RATE	Firm	Long Term	9	8,823	79,404
Duke Energy Florida	2023	Florida Municipal Power Pool	Florida Municipal Power Pool	Exchange	$/MWH	Firm	Short Term	235	0	0
Duke Energy Florida	2023	Florida Power & Light	Florida Power & Light Co	Exchange	$/MWH	Firm	Short Term	278	0	0
Duke Energy Florida	2023	Florida Power & Light	JEA	Exchange	$/MWH	Firm	Short Term	123	0	0
Duke Energy Florida	2023	Gainesville Regional Utilities	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	707	25	17,814
Duke Energy Florida	2023	Gainesville Regional Utilities	Gainesville Regional Utilities	Exchange	$/MWH	Firm	Short Term	14	0	0
Duke Energy Florida	2023	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	5,798	26	148,104
Duke Energy Florida	2023	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Capacity	$/MW-MO	Firm	Long Term	4,900	7,086	34,721,000
Duke Energy Florida	2023	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Energy	$/MWH	Firm	Long Term	587,521	26	15,421,862
Duke Energy Florida	2023	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	585	0	0
Duke Energy Florida	2023	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	14,664	36	522,097
Duke Energy Florida	2023	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	2,279	25	56,034
Duke Energy Florida	2023	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	475	20	9,500
Duke Energy Florida	2023	Southern Co Services Inc	Morgan Stanley Capital Group Inc	Energy	$/MWH	Non-firm	Short Term	7,502	30	221,974
Duke Energy Florida	2023	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	1,802	35	63,760
Duke Energy Florida	2023	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	31,613	27	866,273
Duke Energy Florida	2023	Tallahassee FL (City of)	Tallahassee FL (City of)	Energy	$/MWH	Non-firm	Short Term	3,215	45	144,470
Duke Energy Florida	2023	Tallahassee FL (City of)	Tallahassee FL (City of)	Exchange	$/MWH	Firm	Short Term	47	0	0
Duke Energy Florida	2023	Tallahassee FL (City of)	Tallahassee FL (City of)	Supplemental Reserve	$/MW	Firm	Short Term	94	97	9,120
Duke Energy Florida	2023	Tampa Electric Co	Tampa Electric Co	Capacity	$/MW-MO	Firm	Long Term	750	4,667	3,500,000
Duke Energy Florida	2023	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Firm	Long Term	423,991	39	16,633,496
Duke Energy Florida	2023	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	27,097	50	1,350,450

Seller	Year	Delivery Area	Buyer	Product	Unit Price	Class	Term	Quantity (MWh)	Price ($)	Sales ($)
Duke Energy Florida	2023	Tampa Electric Co	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	254	0	0
Duke Energy Florida	2024	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Capacity	$/MW-MO	Firm	Long Term	464	7,000	3,248,000
Duke Energy Florida	2024	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Energy	$/MWH	Firm	Long Term	106,928	30	3,240,705
Duke Energy Florida	2024	Duke Energy Florida Inc	Central Florida Tourism Oversight District	Energy	$/MWH	Non-firm	Short Term	62,155	23	1,446,560
Duke Energy Florida	2024	Duke Energy Florida Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	113,576	29	3,331,665
Duke Energy Florida	2024	Duke Energy Florida Inc	Florida Municipal Power Agency	Energy	$/MWH	Non-firm	Short Term	4,330	22	95,752
Duke Energy Florida	2024	Duke Energy Florida Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	10,086	39	397,871
Duke Energy Florida	2024	Duke Energy Florida Inc	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	3,700	50	186,150
Duke Energy Florida	2024	Duke Energy Florida Inc	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	100	95	9,500
Duke Energy Florida	2024	Duke Energy Florida Inc	Reedy Creek Improvement District	Capacity	$/MW-MO	Firm	Long Term	213	7,000	1,491,000
Duke Energy Florida	2024	Duke Energy Florida Inc	Reedy Creek Improvement District	Energy	$/MWH	Firm	Long Term	62,591	35	2,160,962
Duke Energy Florida	2024	Duke Energy Florida Inc	Reedy Creek Improvement District	Energy	$/MWH	Non-firm	Short Term	60,990	29	1,748,930
Duke Energy Florida	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Capacity	$/MW-MO	Firm	Long Term	0	7,740	820
Duke Energy Florida	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Customer Charge	FLAT RATE	Firm	Long Term	12	264	3,168
Duke Energy Florida	2024	Duke Energy Florida Inc	Seminole Electric Coop Inc	Energy	$/MWH	Firm	Long Term	105	31	3,217
Duke Energy Florida	2024	Duke Energy Florida Inc	Southeastern Power Administration	Capacity	$/MW-MO	Firm	Long Term	72	2,550	182,626
Duke Energy Florida	2024	Duke Energy Florida Inc	Southeastern Power Administration	Energy	$/MWH	Firm	Long Term	8,181	37	303,780
Duke Energy Florida	2024	Duke Energy Florida Inc	Southeastern Power Administration	Other	$/MW-MO	Firm	Long Term	54,515	1	62,392
Duke Energy Florida	2024	Duke Energy Florida Inc	Southeastern Power Administration	Regulation & Frequency Response	FLAT RATE	Firm	Long Term	4	8,212	32,847
Duke Energy Florida	2024	Duke Energy Florida Inc	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	2,876	23	67,461
Duke Energy Florida	2024	Florida Municipal Power Pool	Florida Municipal Power Pool	Exchange	$/MWH	Firm	Short Term	357	0	0
Duke Energy Florida	2024	Florida Municipal Power Pool	Orlando Utilities Commission	Energy	$/MWH	Non-firm	Short Term	3,325	71	237,450
Duke Energy Florida	2024	Florida Power & Light	Florida Power & Light Co	Energy	$/MWH	Non-firm	Short Term	1,225	69	84,750
Duke Energy Florida	2024	Florida Power & Light	Florida Power & Light Co	Exchange	$/MWH	Firm	Short Term	584	0	0
Duke Energy Florida	2024	Florida Power & Light	JEA	Exchange	$/MWH	Firm	Short Term	111	0	0
Duke Energy Florida	2024	Florida Power & Light	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	98	23	2,254
Duke Energy Florida	2024	Gainesville Regional Utilities	Gainesville Regional Utilities	Exchange	$/MWH	Firm	Short Term	24	0	0
Duke Energy Florida	2024	JEA	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	26,599	22	577,980
Duke Energy Florida	2024	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Capacity	$/MW-MO	Firm	Long Term	8,400	6,801	57,131,000
Duke Energy Florida	2024	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Energy	$/MWH	Firm	Long Term	937,947	26	24,607,513
Duke Energy Florida	2024	Seminole Electric Coop Inc	Seminole Electric Coop Inc	Exchange	$/MWH	Firm	Short Term	307	0	0
Duke Energy Florida	2024	Southern Co Services Inc	Constellation Energy Commodities Group	Energy	$/MWH	Non-firm	Short Term	6,230	24	151,491
Duke Energy Florida	2024	Southern Co Services Inc	EDF Trading North America LLC	Energy	$/MWH	Non-firm	Short Term	183	22	4,106
Duke Energy Florida	2024	Southern Co Services Inc	Energy Authority Inc (The)	Energy	$/MWH	Non-firm	Short Term	14,979	40	600,716
Duke Energy Florida	2024	Southern Co Services Inc	Macquarie Energy LLC	Energy	$/MWH	Non-firm	Short Term	4,744	55	259,800
Duke Energy Florida	2024	Southern Co Services Inc	Morgan Stanley Capital Group Inc	Energy	$/MWH	Non-firm	Short Term	5,333	24	126,525
Duke Energy Florida	2024	Southern Co Services Inc	Oglethorpe Power Corp	Energy	$/MWH	Non-firm	Short Term	11,283	27	302,943
Duke Energy Florida	2024	Southern Co Services Inc	Rainbow Energy Marketing Corp	Energy	$/MWH	Non-firm	Short Term	1,629	43	70,486
Duke Energy Florida	2024	Southern Co Services Inc	Southern Co Services Inc	Energy	$/MWH	Non-firm	Short Term	79,052	19	1,541,363
Duke Energy Florida	2024	Tallahassee FL (City of)	Tallahassee FL (City of)	Energy	$/MWH	Non-firm	Short Term	1,695	91	153,950
Duke Energy Florida	2024	Tallahassee FL (City of)	Tallahassee FL (City of)	Exchange	$/MWH	Firm	Short Term	169	0	0
Duke Energy Florida	2024	Tampa Electric Co	Tampa Electric Co	Capacity	$/MW-MO	Firm	Long Term	500	5,000	2,500,000
Duke Energy Florida	2024	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Firm	Long Term	943,438	36	33,593,239
Duke Energy Florida	2024	Tampa Electric Co	Tampa Electric Co	Energy	$/MWH	Non-firm	Short Term	72,658	35	2,537,331
Duke Energy Florida	2024	Tampa Electric Co	Tampa Electric Co	Exchange	$/MWH	Firm	Short Term	300	0	0

Source: Hitachi Energy, EQR Sales

Data and Methods for the Delivered Price Test for Florida Power & Light's Acquisition of the Vandolah Facility

This exhibit describes data and assumptions used in the delivered price test study ("study") carried out by Secretariat Advisors LLC for Florida Power & Light Company, Inc. ("FPL"). Because the data are voluminous, we provide them in electronic workpapers. This Exhibit has six sections. Section I discusses the study's representative periods. Section II discusses the geographic region and balancing authority areas. Section III discusses generation resources, including adjustments to generating capacity for seasons, maintenance, water availability, and long-term contracts. Section IV discusses the load data. Section V discusses transmission, including transmission pricing and losses. Section VI discusses market prices.

I. Periods

The study calculates market shares and concentration indexes for electric energy for ten representative periods during the year.[1] The year is divided into three seasons (spring/fall, summer and winter), and each season is divided into three or four periods based on NERC on-peak/off-peak definition and peak load levels. The seasons are Spring/Fall, Summer, and Winter.[2] For Spring/Fall, the market conditions correspond to (1) the Top 10% of on-peak load hours for the season, (2) the remaining on-peak load hours, and (3) off-peak hours.[3] For Summer, the Top 1% of on-peak load hours are also considered as a separate period for analysis.[4] Each calculation of market shares and concentration indexes reflects average conditions (e.g., average

1 *See AEP Power Marketing, et al.*, 107 FERC ¶ 61,018 at App. F. ("… analyze: Super-Peak, Peak, and Off-Peak, for winter, shoulder and summer periods, and an extreme Summer Peak, for a total of ten season/load levels.").

2 *Id.*

3 *Id.*

4 *Id.*

loads) during one of the resulting ten periods during the year (e.g., Summer Peak).[5]

The study places each of the periods in each season into three condition categories: off-peak, low peak, and spike. Plant availability (see Section III.A.4 below) vary among these three categories.

Table I-1 summarizes the ten periods considered.

Table I-1– Definition of Ten Periods

Number	*Season*	*Time*	*Abbrev.*	*Condition*	*Hours*	*Description**
1	Spring/Fall	Top 10%	SF_T10	Spike	205	Top 10% of peak hours
2	Spring/Fall	Peak	SF_P	Peak	1843	Remaining peak hours
3	Spring/Fall	Off-Peak	SF_OP	Off-Peak	2344	Off-peak hours
4	Summer	Top 1%	SUM_T1	Spike	11	Top 1% of peak hours
5	Summer	Top 10%	SUM_T10	Spike	103	Top 10% of peak hours
6	Summer	Peak	SUM_P	Peak	921	Remaining peak hours
7	Summer	Off-Peak	SUM_OP	Off-Peak	1184	Off-peak hours
8	Winter	Top 10%	WIN_T10	Spike	100	Top 10% of peak hours
9	Winter	Peak	WIN_P	Peak	892	Remaining peak hours
10	Winter	Off-Peak	WIN_OP	Off-Peak	1192	Off-peak hours

Note: *Peak hours include hours between 7 a.m. through 11 p.m. Eastern Time weekdays, excluding six major holidays. Off-peak hours = Hours between 11 p.m. through 7 a.m. on weekdays and all weekend and holiday hours. Hour counts based on 2024 historical load data.

The Off-peak periods include hours starting at 11 p.m. through 7 a.m. Eastern time plus all other hours on weekends and the six major holidays.[6] The Off-peak periods have off-peak transmission pricing and plant availability.

To identify the Top 1%, Top 10%, and Peak periods for a given season, we removed all Off-peak hours from that season. We then ranked the remaining (peak) hours based on load levels in each destination market by season. We then defined the Top 1% and Top 10% as the 1% and 10% of these remaining hours in which loads

5 *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶31,044, 30,130 (1996) ("Applicants should present separate analyses for each of the major periods when supply and demand conditions are similar. One way to do this is to group together the hours when supply and demand conditions are similar; for example, peak, shoulder and off-peak hours.").

6 Major holidays are New Year's, Memorial Day, 4th of July, Labor Day, Thanksgiving and Christmas.

in the destination market were highest. These periods have spike transmission pricing and plant availability. The remaining On-peak hours comprise the Peak period, which has peak transmission pricing and plant availability.

II. Geographic Region

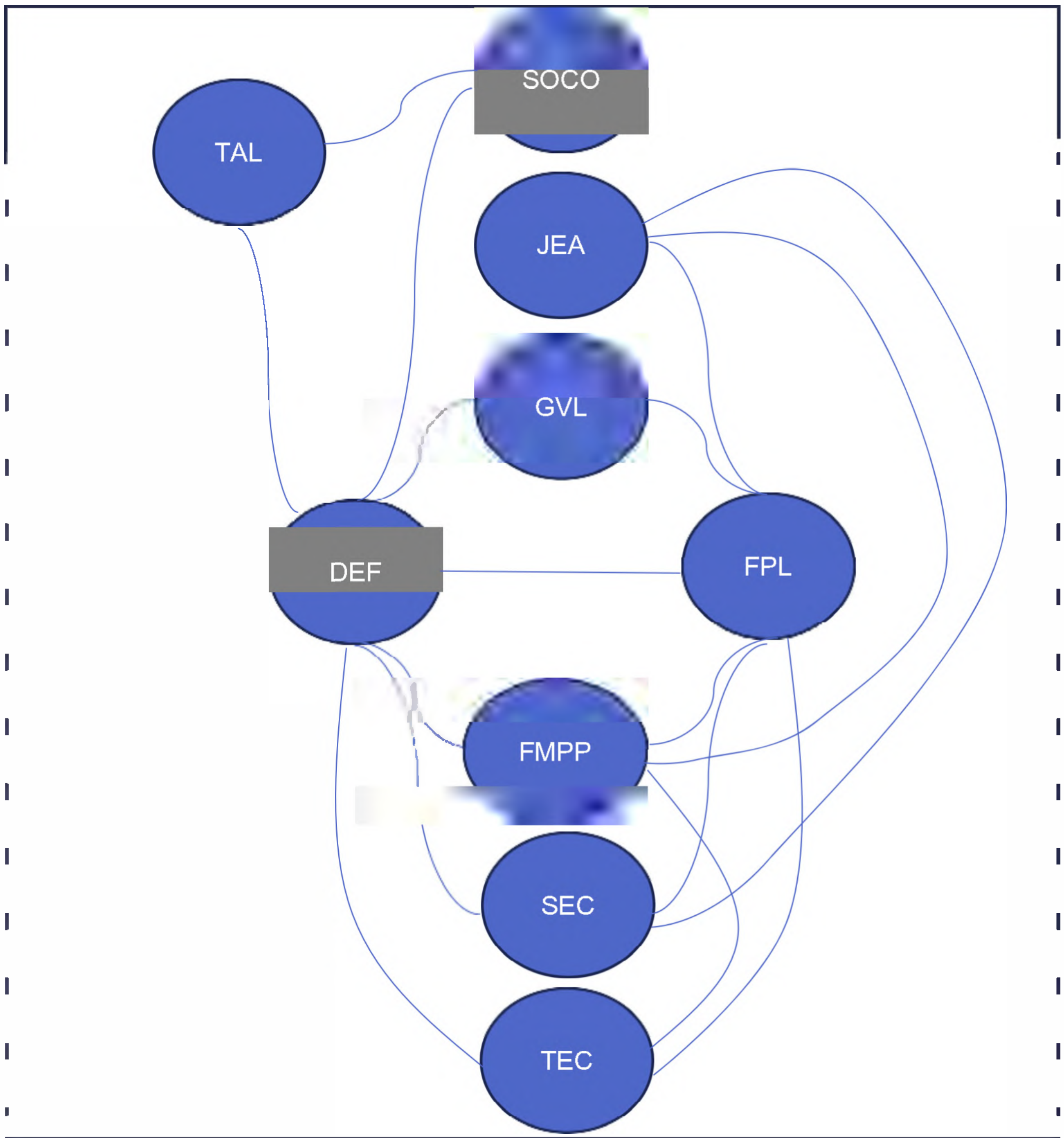
The study includes data for a geographic market that consists of DEF and Balancing Authority Areas (BAAs) that are first-tier to DEF. Table II-1 lists these market areas and their abbreviations.

Table II-1 – List of Supply Areas and Study Destinations

Abbreviation	*Full Name*	*Study Destination*
DEF (or FPC)	Duke Energy Florida	Yes
FMPP	Florida Municipal Power Pool	Yes
FPL	Florida Power & Light	Yes
GVL	Gainesville Regional Utilities	Yes
SEC	Seminole Electric Cooperative	Yes
SOCO	Southern Company	Yes
TAL	City of Tallahassee	Yes
TEC	Tampa Electric Co	Yes
VAND	Vandolah	

Figure II-1 shows a diagram of the areas and the transmission structure for the FRCC. Vandolah is part of the DEF (a/k/a FPC) BAA. DEF in turn is interconnected with FMPP, FPL, GVL, NSB, SEC, SOCO, TAL, and TEC. FPL is interconnected DEF, FMPP, GVL, JEA, SEC, SOCO, and TEC. Each bubble on the diagram is a BAA and has its own Simultaneous Import Limit (SIL) that limits the total amount of imported energy that is allowed to enter the BAA for FERC Delivered Price Test (DPT) share and HHI calculations. For most transactions, this transmission topology would be used for both pre-transaction and post transaction situations. This transmission set-up could be used if Vandolah were to stay in the DEF BAA post-transaction and FPL would import energy from Vandolah via daily firm or hourly non-firm point-to-point transmission reservations on the DEF system and using non-firm secondary reservations using NITS service on the FPL transmission system. In section V we discuss the changes to the transmission network to handle Vandolah moving from DEF to FPL.

Figure II-1 – Supply Areas and Transmission Links



III. Generation

A. Generation Capacity and Ownership

The study includes generating units located in the geographic region that are connected to the power grid.

1. Generating Unit Data

The study uses data for summer and winter capability at the unit level reported in the Velocity Suite Generation Unit Capacity database available from Hitachi Energy, Inc.[7] We supplemented with information from NextEra's Asset Appendix (Serial Number 27755 filed with FERC on May 29, 2025); EIA-Form 860M (April 2025); FPL's and DEF's 10-year site plans, and DEF's Asset Appendix. The universe of units includes all units with a status of operating, standby, cold standby, restart, testing, or under construction that will be online before July 15, 2027, and a retirement date after December 31, 2022. Generation units online on December 31, 2023, are used in the historical base price simulations for the years 2023-2024. For the forward price simulations and the DPT calculations, the inclusion of units varies by season. For the Spring/Fall and Winter season, the inclusion cut-off date is January 15, 2028. The cut-off date is the date at which if a unit was online before or retired after this date the unit was, on average, operating during the season and therefore included in the study calculations. The cut-off date for the Summer season is July 15, 2027. Hence, the study represents, on average, the period from June 2027 through May 2028.

2. Ownership

The study relies primarily on Velocity Suite for determination of unit ownership. For NextEra and Duke units we verified these data using the Asset Appendices filed

7 Order No. 642, at 31,887 ("For each potential supplier to a relevant market, applicants must file the publicly available generation capability and variable cost data for each generating plant or unit. … cost data at the unit level are preferable to cost data at the plant level, and applicants must file disaggregated plant data to the extent it is publicly available.")

at FERC. For a few cases, we relied on other sources.[8] These data are supplemented from data at Secretariat on plant ownership. For NextEra and DEF generation, the study relies upon Asset Appendix data from market-based rate filings and updates from the companies to determine plant ownership. The workpapers contain a reference that compares plant names from Velocity Suite, EIA 860, and the NextEra Asset Appendix. Before calculating market shares and market concentration, capacities of holding company entities are aggregated to the holding company level.

3. Seasonal variation in capability

The study uses summer and winter capability data from Velocity Suite and EIA 860 in the case of NextEra and DEF units. Spring/fall capacities are the average of summer and winter capacities.

4. Adjustments to Generating Capability

The generating capability figures used for each period are obtained by multiplying the seasonal capabilities by an availability factor, which is based on the period, unit location, and NERC Generating Availability Data Systems (GADS) category of the unit. Data from 2019 through 2023 were used because those were the latest available on the NERC web site as of June 2, 2025. The GADS database gives national average operating information for generating units by unit type and size. For example, it gives data for coal-fired steam units with capacities between 300 MW and 399 MW.

For each period and each generating unit, the availability factor adjusts for the following.

8 For example, NextEra's Tupelo solar facility was inadvertently missing from their Asset Appendix. That apparently will soon be rectified (if it has not already).

a) *Unplanned outage rates by GADS category*

For a given GADS category, the study assumes that unplanned (forced) outage rates (as a share of generating capability available after allowing for planned outages) are constant across seasons and generating units, regardless of owner. Based on GADS data for 2019-2023, the study calculates an equivalent forced outage rate (EIFOR), which measures the share of generating capability in a GADS category that is not available because of forced outages. The computation is EIFOR = (FOH)/AH, where FOH is number of forced outage hours and AH is total hours available for generation after planned outages (but before forced outages).[9]

b) *Planned outage rates by GADS category and season*

With four exceptions (hydro, storage, wind, and solar units), the study assumes that the planned outage rate is constant for all generating units for a given GADS category, area, and season. For a given GADS category, the share of hours of generating capability that is not available as a result of planned outages is computed as (POH + POEH)/PH; where PH are the period hours, POH are the hours not available because of planned outages, and POEH are the hours not available because of planned outage extensions.

Based upon planned outages during monthly peak hours each season reported in FERC Form 714 by BAA,[10] the annual outage percentage is allocated to each season. Because outages are likely to be "managed" to minimize disruptions,[11] the average planned outage rates during peak periods by season are adjusted.

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9 EIFOR differs slightly from the EFOR provided in the GADS data. EIFOR provides a better measure of a forced outage rate for peaking units that are operated a small percentage of the year.

10 See Order No. 697, at P 43 ("Planned outage amounts should be consistent with those as reported in FERC Form No. 714.").

11 For example, planned maintenance on hydro facilities may take place in summer because not enough water may be available to operate all the generators. In such a case, there is a planned outage, but it does not diminish the capability of the generation fleet.

Specifically, the planned outage rate for summer season is set to 0.[12] In winter, instead of taking the seasonal average, we take the lowest level of planned during the three winter months. For Spring/Fall, we used the average of the planned.

c) Variation in hydro availability across seasons and periods

In general, utilities use hydro facilities to generate energy during the hours when energy prices are highest, subject to constraints imposed by availability of water and reservoir capacity. To incorporate these constraints, the study proceeds in the following manner.

First, the study uses EIA Form 923 monthly production data for the period 2019 to 2023 to compute average hourly hydro generation by season.[13] Average hourly generation is then divided by hydro capability to give an average hourly hydro operating rate by season.

Second, depending upon the level of the hydro operating rate for a given season, the study calculates availability factors for the spike, peak and off-peak periods. When the historical seasonal operating rate is below 30 percent, the availability factor for each period in the season is set equal to the operating rate; the 30 percent figure is an assumed "run of river" constraint. The study assumes that prospectively the maximum operating rate is 90 percent; this is the assumed "maximum rate" constraint. When the historical seasonal operating rate is above 90 percent, the availability factor for each period is set to 90 percent, absent information indicating that the actual capacity is greater than that reported by ABB.

When the seasonal operating rate is above the run of river constraint and below

[12] *AEP Power Marketing et al.*, 107 FERC ¶ 61,018, P 97 (2004) ("We do not expect that applicants will have planned generation outages scheduled for the annual peak load day.")

[13] Order No. 697, P 344 ("With regard to energy-limited resources, such as hydroelectric and wind capacity, in lieu of using nameplate or seasonal capacity in their submissions, we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor …")

the maximum rate, we reason that the hydro generator owner would be likely to produce a higher level of energy during spike hours, when energy prices are highest, than during other peak hours, and that the owner would be likely to produce a higher level during peak than during off-peak hours.

Based on this reasoning, when the seasonal operating rate is between the run of river constraint and the maximum rate, as is the case for each of the three seasons, the study uses a spike availability factor of 90 percent, which is the assumed maximum operating rate, and off-peak availability factor of 30 percent, which is the assumed run-of-river constraint, and a calculated availability factor for the peak periods, as described below.

The seasonal peak availability factor is calculated with actual total seasonal hydro generation. The study then computes the hydro generation during all spike and off-peak hours, assuming the generation rates implied by the spike and off-peak derate factors computed in the manner described above. The study then calculates total remaining peak hydro generation as the difference between total seasonal hydro generation and the sum of hydro generation during all spike and off-peak hours. The seasonal low peak availability factor is computed as total low peak hydro generation divided first by the number of hours in the off-peak period and then by hydro generating capacity.

d) Variation in pumped storage availability across seasons and periods

We assume that pumped storage units have 90% availability during Top 1% and Top 10% periods, 50% availability during Peak periods, and no availability during Off-peak periods.

e) Wind availability

For each area-owner combination, we calculate average operating rates from

2019 through 2023 by season from EIA-923 data.[14] The average operating rates are the availability factors. When operating rates are not available for an owner in an area, we use the average operating rate for that area. For example, a new facility in an area in 2024 would have the average operating rate for the units online in 2019-2023 imputed to it. Seasonal operating rates are then shaped by hourly wind output reported by the RTOs.

f) Solar availability

Availability for solar power is also calculated based on average operating rates from 2018 through 2023 reported in EIA-923.[15] The seasonal operating rates are then shaped by hourly solar output by hour reported by EIA-930 data.

g) Batteries

The battery type affects the battery availability. We assume batteries are discharged twice per day, once in the morning hours and once in the late afternoon or evening hours. Older batteries typically have one or two hours of storage, and newer batteries (including all the new FPL batteries) have four hours of storage. Given the discharge times the study assumes that batteries charge during the night, discharge in the morning, charge again during peak solar output, and then discharge during peak demand (net of solar production). The study then calculates how often the discharge hours occur during the Top 1% period, Top 10% period, and remaining peak hours. Based on this reasoning, Table III-1 shows the availability factors the study gives to different batteries.

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[14] Order No. 697, P 344 ("With regard to energy-limited resources, such as hydroelectric and wind capacity, in lieu of using nameplate or seasonal capacity in their submissions, we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor …")

[15] *Id.*

Table III-1 Battery Availability

	1 Hour	2 Hour	4 Hour
Top 1%	0.95	0.98	0.99
Top 10%	0.47	0.52	0.72
Remaining Peak	0.43	0.46	0.47
Off-peak	0.24	0.22	0.19

Source: In workpapers.

B. Variable Costs of Generation

The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs.[16] The study calculates fuel costs from unit heat rates and projected forward prices. Historic fuel prices during the base period come from (in order of preference in the data): (1) Gas Daily natural gas prices; (2) EIA Form-923 fuel cost data (spot prices when available); (3) Velocity Suite monthly estimates of fuel costs; (4) Velocity Suite estimates in generation data; (5) averages of other units with similar fuel in the region. Then the difference between forward prices for prompt-month deliveries in the base period (by season) and forward prices in the study period (by season) are added to the historical prices to give the expected price for 2027/28 for each unit.[17] The forward fuel prices were downloaded on May 5, 2025.

The study uses unit-specific fuel costs, especially for natural gas units. We translate the ICE gas price hub name reported by Velocity Suite to a Gas Daily Price point. When available, we use the Gas Daily prices for historical prices. The average prices are calculated by destination and period, to account for different prices based

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[16] 18 CFR §33.3(d)(2) ("For each generating plant or unit owned or controlled by each potential supplier, the applicant must also provide variable cost components. (i) These cost components must include at a minimum: (A) Variable operation and maintenance, including both fuel and non-fuel operation and maintenance; and (B) Environmental compliance.")

[17] For example, for natural gas prices, the NYMEX Henry Hub forward price for summer 2022 on April 30, 2020 was \$2.267/mmBtu and the average summer NYMEX closing prices for summer 2018-2019 was \$2.626/mmBtu. The difference, \$-0.359/mmBtu, is then added to the historical natural gas prices at each location to give the measure of likely natural gas prices in the summer of 2022. For Hardin, the average historical price for the SUM_T1 period with MISO as the destination was \$2.927/mmBtu, so the fuel price for SUM_T1 2022 is \$2.568/mmBtu (=\$2.927 + \$-0.359).

on different days that have peak hours at each destination. Other prices (e.g., oil and coal) are calculated by season. All fuel price data is unit specific when unit specific or plant-specific data are available.

The study uses SO2, NOX, and CO2 emission rates during the base period to calculate the emission costs. Those rates are multiplied by emission prices that vary by location.

Finally, the other variable operating and maintenance costs (VOM) are added to the dispatch costs. The study used VOM reported by Velocity Suite.

C. Long-term Contracts

The Commission requires adjustments to capacity based upon long-term purchase and sales contracts.[18] The study uses Asset Appendix data from market-based rate filings and FERC Form 1 filings to obtain data on long-term contracts. We also reviewed contract data from Velocity Suite's list of unit contracts. Where data indicate a change of control of energy, we include a contract transferring control to the buyer. We leave the generation unit in the BAA where it is physically interconnected to the transmission system. Known purchases from outside of the geographic region to a buyer in the region are included as resources in the importing area, and known sales from inside of the region to buyers outside of the region are excluded as resources.

As with the inclusion of generation units, contracts are included based upon the midpoint of each season. The study only includes contracts in a season that begin before the midpoint and end after the midpoint. The study considers only contracts of a year or longer duration.

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18 *See* Order No. 642, at 31,887 ("… data regarding the long-term purchases and sales of suppliers should be filed with the application. These data would, to the extent available, include the buyer, the seller, the contract duration, the degree of interruptibility, the quantity (MW), and the capacity and energy charges. Applicants must explicitly show any adjustments made to suppliers' capacity due to long-term contracts.")

IV. Load for AEC Calculations

The report uses load obligations from information available from public sources such as FERC Form 714 and EIA Form 861. The calculation is performed in five steps. First, the hours in each period are identified based on time and load level for the two destinations: DEF and FPL.[19] Second, load "shapes" are calculated so that the annual load level in EIA 861 data can be translated into a load amount during each of the 10 periods. Third, the annual loads served by state and balancing area are then merged with the shapes to give the expected load level served in each period. Fourth, when actual hourly load data for an entity are available (e.g., from Form 714), we use the actual hourly load data. In the southeastern United States, most load obligations come from FERC Form 714. Finally, an "obligation" amount is applied to each of the calculated load levels. Because Florida is a traditional market region, the study assumes that all load obligations in Florida are 100% of reported loads.

Load growth from the 2023-2024 historical period is based upon forecasted load growth for total energy reported in FERC Form 714 for 2023-2024 and the 2027 forecast year.

V. Transmission

A. Transmission Network

The study incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas in each Region is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed.

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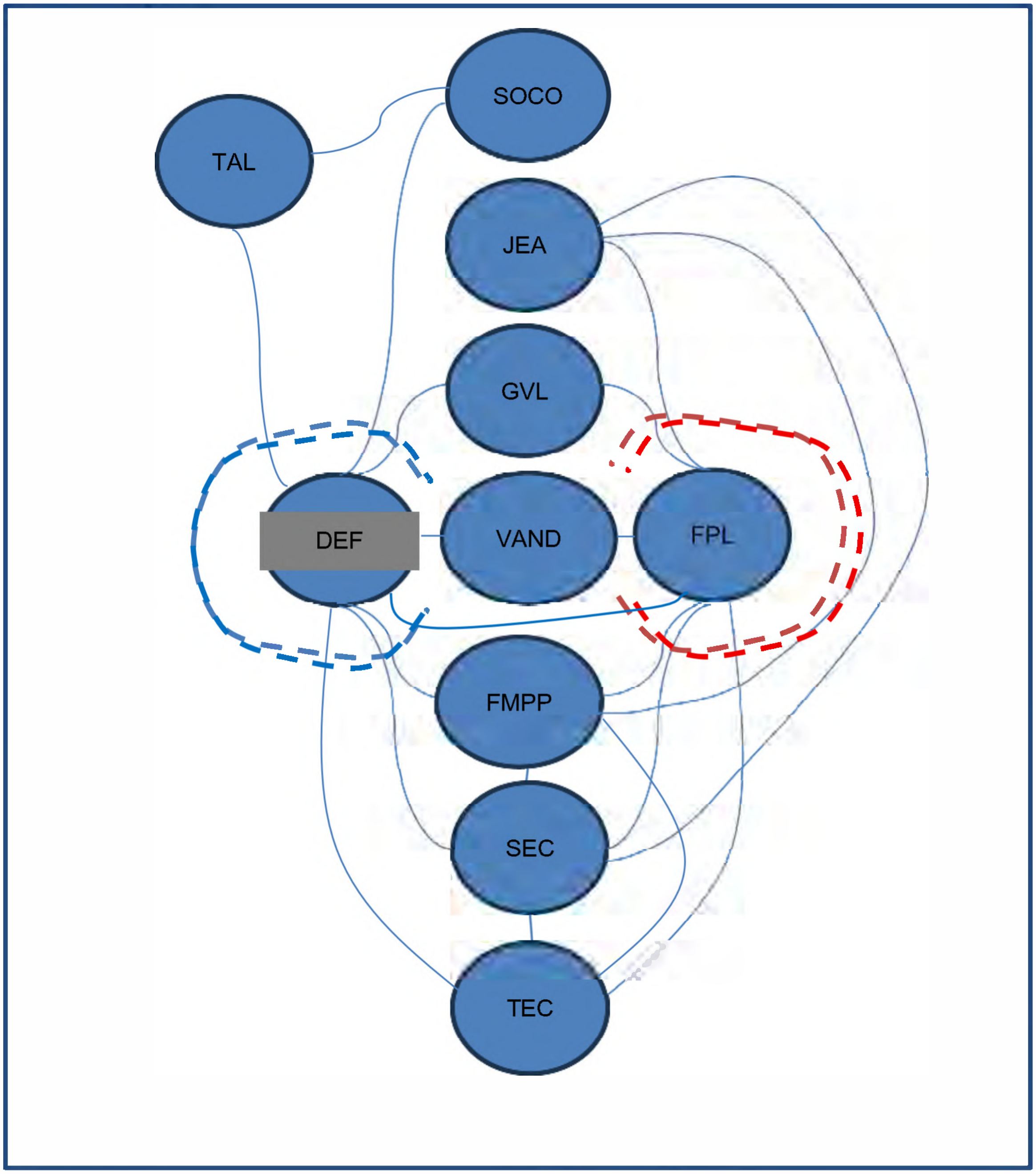
19 MISO reports hourly load data for six different regions (LRZ1; LRZ2 & 7; LRZ3 & 5; LRZ4; LRZ6; and LRZ8, 9 & 10). These are aggregated for the total MISO loads. Load data for LRZ8, 9 & 10 correspond to MISO South. Hourly data for WOTAB were provided by Entergy based on their 2020 Business Plan and included in confidential workpapers.

The transmission topology in Figure II-1, above, works adequately for the Alternate case where Vandolah stays in the DEF BAA. But in the Base Case, Vandolah moves from the DEF BAA pre-transaction to the FPL BAA post-transaction. To handle this movement the study moves Vandolah to a separate area, VAND, situated between DEF and FPL, as shown in Figure V.A.1. The figure shows VAND directly connected to DEF and FPL and two simultaneous constraints. The simultaneous constraint around DEF on the left covers all transmission paths to DEF except from VAND. In the pre-transaction Base Case and the Alternate Case, the simultaneous limit around DEF is set to the SIL value, the transfer capability from VAND to DEF is equal the size of Vandolah, a priority (firm transmission reservation) is created so that any capacity of VAND will move to DEF, and the transfer capability to and from VAND and FPL is set to zero. In this way, VAND is “in DEF” for the DEF destination. For other destinations, the Vandolah capacity has to flow through DEF to the other locations. The simultaneous constraint around FPL on the right covers all transmission paths to FPL except from VAND. In the post-transaction Base Case, the simultaneous limit around FPL is set to the SIL value, the transfer capability from VAND to FPL is equal the size of Vandolah, a priority is created so that any capacity of VAND will move to FPL, and the transfer capability to and from VAND and DEF is set to zero. In this way, VAND is “in FPL” for the FPL destination, and for other destinations the Vandolah capacity has to flow through FPL to the other locations.

Figure V.A.1 — Flexible Transmission Topology



B. Transmission and Ancillary Services Pricing and Losses

As specified by the Commission, the study generally uses ceiling prices for transmission service from Schedules 1, 2 and 8 of the utility's *pro forma* open-access transmission tariff.[20] Transmission providers may require transmission customers to purchase ancillary services under Schedule 1 (scheduling, system control and dispatch) and Schedule 2 (reactive supply and voltage control). Schedule 8 gives the rates for non-firm point-to-point transmission service. The study uses transmission prices from tariffs.

When we have tariffs available, we calculate rates for off-peak, peak and spike categories. Because of discounting and the nature of baseload purchases, off-peak rates are often lower than peak rates.[21] We use two steps to determine off-peak rates. Step 1: When a utility posts off-peak hourly rates, we use the posted rates. Step 2: When a utility does not post off-peak hourly rates, we calculate an hourly off-peak rate based on other tariff information. To calculate hourly off-peak rates, we divide the weekly rate by 168, the number of hours in a week. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

We use similar steps to determine peak rates. Step 1: When a utility posts maximum hourly rates in its tariff, we use the maximum tariff rates. Step 2: When a utility does not post off-peak hourly rates, we calculate a peak rate based on other

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[20] *See* 18 CFR 33.3(d)(5)(i) ("The applicant must use in the horizontal Competitive Analysis Screen the maximum rates stated in the transmission providers' tariffs."); 18 CFR 33.3(d)(5)(iii) ("The following data must be provided for each transmission system that would be used to deliver energy from each potential supplier to a destination market: (A) Supplier name; (B) Name of transmission system; (C) Firm point-to-point rate; (D) Non-firm point-to-point rate; (E) Scheduling, system control and dispatch rate; (F) Reactive power/voltage control rate; (G) Transmission loss factor; and (H) Estimated cost of supplying energy losses.") Because on-peak non-firm rates are typically higher than firm rates (which are only daily), the study uses the sum of the Scheduling, system control and dispatch rate (Schedule 1);) Reactive power/voltage control rate (Schedule 2); and the Non-firm point-to-point rate (Schedule 8) for the transmission rate.

[21] For transactions longer than one hour, the *pro forma* tariff caps the amount that the purchaser pays per day by the daily rate, and the amount that the purchaser pays per week by the weekly rate.

tariff information. To calculate hourly peak rates, we divide the weekly rate by 80—the "Appalachian" method. When tariffs specify fees on a per transaction basis, we divide them by 25 to put them on a per MW basis.

For spike periods, we use ceiling hourly rates from tariffs, when available. Otherwise, we use the Appalachian method.

Whenever practical, the study uses loss rates from tariffs. When these methods did not provide a loss rate for a particular utility, the study assumes that losses are three percent per utility.[22] The study assumes that transmission customers pay losses in-kind. That is, if area A exports 100 MW to area B and the losses are 3 percent, only 97 MW arrive at area B.

For areas where tariffs are not available, rates and losses are the average by period for all the reporting areas.

C. Transfer Capability and SILs

The geographic market includes FPL, DEF, and their first-tier BAAs. Because FPL plans on moving the Vandolah from the DEF to the FPL BAAs, we performed forward looking SIL studies for the summer of 2027 and winter 2027/2028. The SIL calculations are described in Exhibit JM-7 and provided in workpapers. The PASS DPT program moves" the amount of additional generation to match the transmission reservations (when available) and subtracts the remaining reservation. The remaining uncontracted transmission availability is allocated pro-rata consistent with the Commission's instructions. For transmission availability, we use monthly total transfer capability (TTC) and available transfer capability (ATC) posted on OASIS. Most ATC values typically are for the period from May 2025 through April 2026. When no valid data are available, we use the most recent valid ATC data that we maintain. The ATC

[22] Losses of 3 percent are representative of the industry. See, FERC Open Access NOPR, *FERC Stats & Regs*, ¶32,514 at 33,150 (1995).

value used in the study is the maximum of TTC less Transmission Reliability Margin (TRM), posted firm ATC, and posted non-firm TTC.[23]

VI. Market Prices

The study uses 2023-2024 daily and hourly EQR transactions for market prices. We begin with median prices by DPT period. The study then runs two price simulations for each destination market: one for the base period and one for the forward test period. The differences in the forward prices compared to the base period prices in the simulation then are added to the actual base prices to give a forecast of the forward price that accounts for changes in fuel costs, the generation fleet, and load levels. Finally, because some areas in Florida are thinly traded and do not produce representative prices, we place the prices within a range. The minimum price is the FPL price for the period less the transportation costs to FPL. The maximum price is the FPL price plus the cost of transferring energy from FPL to the destination market.

Table VI-1 shows the shows the market prices at each destination in each of the ten periods that are used in the DPT study.

[23] For TRM, we used the maximum of the non-firm and firm TRM in the posting.

Table VI-1 – Representative Market Prices
($/MWh)

Season / Period	FMPP	FPC	FPL	GVL	JEA	SEC	SOCO	TAL	TEC
SF_T10	51.78	53.18	43.88	220.20	61.51	56.38	54.16	66.45	60.79
SF_P	48.45	33.94	37.63	81.80	37.56	37.74	42.16	51.25	50.99
SF_OP	33.06	31.48	34.12	57.53	30.38	36.45	37.05	40.97	38.34
SUM_T1	40.01	62.32	60.20	54.00	63.06	62.95	74.81	83.59	78.55
SUM_T10	73.55	55.27	48.08	42.68	53.28	64.11	71.21	70.24	67.92
SUM_P	52.21	38.52	44.35	35.24	47.96	53.12	47.16	54.42	55.21
SUM_OP	39.78	32.67	38.09	29.96	36.63	41.87	44.00	40.77	39.17
WIN_T10	42.84	49.33	40.13	76.88	58.66	40.13	55.36	60.28	50.54
WIN_P	52.81	34.68	38.94	68.04	45.19	49.97	39.34	48.96	47.80
WIN_OP	44.06	34.71	37.51	67.84	43.21	40.48	37.22	38.28	38.34

Technical Appendix:

Methods Used to Compute Concentration

Secretariat Advisors, LLC
2121 K Street, NW
Suite 1100
Washington, DC 20037
(202) 223-4700

March 2025

This Exhibit describes the methods used to calculate market shares and concentration in destination markets.

Allocation of scarce transmission capability is accomplished using linear and nonlinear programs that model generation dispatch and the contract path transmission system. This Exhibit provides an overview of the structure of the programs and presents the equations.

Overview of Linear Program

The linear program models control areas as nodes in a transmission system. Each node has a demand for and a supply of electric energy. The supply is based on the generators at the node and potential deliveries to the node via transmission links from other control areas. The linear program allows for net import and export limits to and from an individual control area. Given generation capability and costs and transmission capability and costs, the linear program finds the least-cost solution that satisfies the specified loads. Costs are defined as dispatch (generation) costs plus transmission costs including losses plus the default cost for "unserved" load. For each solution, the linear program determines the quantities produced in, exported from, and imported into each control area.

The Mathematical Equations

The linear program to be solved is given below:

Minimize Total Cost: $Cost = GC + TC + UC$

Subject to:

(1) Generation: $TG_a = \sum_{u}^{u \in a} G_{a,u}$ for each area *a*;

(2) Imports: $YI_a = \sum_{b}^{a,b \in network} (1 - h_{b,a}) T_{b,a}$ for each area *a*;

(3) Exports: $YE_a = \sum_{b}^{a,b \in network} T_{a,b}$ for each area *a*;

(4) Net Imports: $Y_a = YI_a - YE_a$ for each area *a*;

(5) Supply/Demand Balance: $TG_a + Y_a + U_a = D_a$ for each area *a*;

(6) Generation Cost: $GC = \sum_{a} \sum_{u}^{u \in a} d_{a,u} G_{a,u}$ for each area *a*;

(7) Transmission Cost: $TC = \sum_{a,b}^{a,b \in network} r_{a,b} T_{a,b}$ for each path *a* to *b*;

(8) Unfilled Demand Cost: $UC = \sum_{a} pU_a$ for each area *a*;

(9) Generation Limits: $g\min_{a,u} \le G_{a,u} \le g\max_{a,u}$ for each unit *u* in each area *a*;

(10) Transmission Limits: $t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$ for each link *a* to *b* in the transmission network; and

(11) Net Import Limits $Y\min_a \le Y_a \le Y\max_a$ for each area *a*;

where:

a,b	are subscripts for control/transmission areas;
Cost	is total system cost;
$d_{a,u}$	is the dispatch cost of unit *u* in area *a*;
D_a	is demand for power in area *a*;
$G_{a,u}$	is generation output of unit *u* in area *a*;
GC	is total system generation cost;
$Gmax_{a,u}$	is the maximum output of unit *u* in area *a*;
$Gmin_{a,u}$	is the minimum output of unit *u* in area *a*;
$h_{b,a}$	is the fraction of power lost to resistance from moving power from area *b* to area *a*;
N	is a subscript to identify simultaneous transmission constraint *n*;
P	is the default price;

$r_{a,b}$	is the transmission rate from area *a* to area *b*;
$T_{a,b}$	is the power flow from area *a* to area *b*;
TC	is total system transportation expenses;
TG_a	is total generation output in area *a*;
$t\ \max_{a,b}$	is the maximum power flow from area *a* to area *b*;
$t\ \min_{a,b}$	is the minimum power flow from area *a* to area *b*;
U	is a subscript to identify units in an area;
U_a	is the amount of demand in area *a* not met by generation or imports
UC	is total system cost of not meeting demand;
Y_a	is net imports into area *a*;
YE_a	is total exports from area *a*; and
YI_a	is total imports into area *a*;
$Y\ \min_a$	is minimum net imports in area *a;*
$Y\ \max_a$	is maximum net imports in area *a.*

This linear program is solved using the BDMLP solver in GAMS. In order to calculate concentration for different destinations, seasons, and periods, the PASS GAMS program loops through the destinations, seasons, and periods with calls to Solvers to solve the linear programs. Loads, unit availability and transmission availability are adjusted for each season-period combination.

Calculating Concentration

Transmission allocation is accomplished in four steps. In the first step the linear program finds the net-back prices in all control areas given a price at the destination control area equal to 105 percent of the pre-merger price. Suppose the pre-merger price at the destination, control area A, is \$20/MWh. Then all generation capability with a dispatch cost of \$21/MWh or less in the destination area would be included in the market because \$21 is 105 percent of \$20. If transmission cost (including losses) is \$5/MWh from control area B to A, then the net-back price at B would be \$16/MWh, which is the \$21/MWh less the \$5/MWh transmission cost between B and A. Then, all generation capability at B with dispatch costs equal to or less than \$16/MWh would be included in the market if there were no transmission constraints. Calculation of net-back prices is accomplished by setting the default price, *p*, equal to 105 percent of the pre-merger price at the destination, setting load at the destination to a high number and loads elsewhere to zero, setting transmission limits high enough so that the transmission system is not constrained, and setting a limited amount of generation in each area with a zero dispatch cost. The shadow prices produced by the linear program will be *p* at the destination and the relevant net-back prices in other areas.

In the second step, one calculates Economic Capacity (EC) and Available Economic Capacity (AEC) in each area. These values are then used to limit generation capability. The ownership shares of AEC and EC are calculated for each node in the system.

In the third step, the linear program determines the amount of energy that can be imported into an area given available EC (or AEC) and limits on transmission capacity. This is accomplished by limiting generation in each area to the capacity amount (EC or AEC), giving generation outside the destination market a lower cost than generation inside the destination market, and minimizing cost to serve a large load at the destination market. The amount of generation supplied to the destination is the maximum that can be imported into the destination market.

In the fourth step, transmission is allocated by the following non-linear program:

Minimize Loss: $$Loss = \sum_{\alpha} \left(\frac{C_{\alpha}^{2}}{Y_{Dest} s_{\alpha}} - 2C_{\alpha} \right)$$

Subject to:

(1) Pre Shares: $s_\alpha = \dfrac{C\max_\alpha}{\sum_\beta C\max_\beta}$ for each area α;

(2) Allocated Shares: $A_\alpha = \dfrac{C_\alpha}{Y_{Dest}}$ for each area α;

(3) Imports: $YI_a = \sum_b^{a,b\in network} (1-h_{b,a})T_{b,a}$ for each area *a*;

(4) Exports: $YE_a = \sum_b^{a,b\in network} T_{a,b}$ for each area *a*;

(5) Net Imports: $Y_a = YI_a - YE_a$ for each area *a*;

(6) Supply/Demand Balance: $C_a + Y_a + U_a = D_a$ for each area *a*;

(7) Capacity Limits: $c\min_a \le C_a \le C\max_a$ for each area *a*;

(8) Transmission Limits: $t\min_{a,b} \le T_{a,b} \le t\max_{a,b}$ for each link *a* to *b* in the transmission network; and

(9) Max Import Limit Y_{Dest} = Maximum imports from step 3;

where:

a,b are subscripts for control/transmission areas;

α,β are subscripts for control/transmission areas other than the destination market;

s_α Is area α's share of capacity outside of the destination;

A_α is area α's share of allocated capacity outside of the destination;

$Loss$ is the loss function to be minimized.

The loss function is derived from the weighted squared-errors between the pre-allocation shares and the post-allocation shares, where Y_{Dest}/s_α are the weights. For each source control area, the weighted squared-error is given by:[1]

$$W_\alpha = \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2.$$

Accordingly, the sum of the weighted squared-errors gives rise to the loss function, which can be seen by:

$$\begin{aligned} Loss &= \sum_\alpha W_\alpha \\ &= \sum_\alpha \frac{Y_{Dest}}{s_\alpha}(A_\alpha - s_\alpha)^2 \\ &= \sum_\alpha \frac{Y_{Dest}}{s_\alpha}(A_\alpha^2 - 2s_\alpha A_\alpha + s_\alpha^2) \\ &= \sum_\alpha \left(\frac{C_\alpha^2}{Y_{Dest} s_\alpha} - 2C_\alpha \right) + \text{constant}. \end{aligned}$$

The resulting shares from minimizing this loss functions preserve the relative shares of capacity behind any transmission constraint going to the destination. This can be seen from the following LaGrangian equation to be minimized:

$$L = \sum_i \left(\frac{C_i^2}{Y_{Dest} s_i} - 2C_i \right) + \lambda \left(T - \sum_i C_i \right),$$

where T is the transmission limit affecting control areas i. The first order conditions are:

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[1] This exposition ignores the adjustments necessary to give priority to minimum transfer levels from a source area to the destination.

$$\frac{\partial L}{\partial C_i} = \frac{2C_i}{Y_{Dest} s_i} - 2 - \lambda = 0,$$

which can be rearranged to give:

$$A_i = \frac{C_i}{Y_{Dest}} = \left(\frac{2+\lambda}{2}\right) s_i,$$

which shows that the allocated market shares of those areas affected by the transmission constraint are proportional to their shares of capacity before the transmission allocation. Moreover, this is the only transmission allocation method that maintains the relative shares of capacity behind any binding transmission constraint in the allocation process.

This non-linear program is solved using the COINIPOPT solver in GAMS. The calculated capacities from the nonlinear program above less transmission losses determine the capacities for the market share calculations for sources outside of the destination market. The capacities within the destination market are given full weights.

Market concentration is the HHI, which is the sum of the squared market shares. Mathematically,

$$HHI = \sum_{i=1}^{n} S_i^2,$$

where S_i is the allocated share of firm *i* and *n* is the number of firms in the market. Firms with shares of 0.7 percent or less are excluded from the HHI calculation. The reason is that the squared-share is less than one-half, and rounding to a whole number gives an HHI contribution of zero. The summary sheets combine all the firms with shares of 0.7 percent or less (other than Applicants) into the "Other" category. The collective share of the Other category does not enter the

HHI calculation other than the represented capacity reduces the shares of the other market participants.

Technical Appendix:

Calculating SILs for Florida Power & Light Company

Secretariat Advisors LLC
2121 K Street, NW
Suite 1100
Washington, DC 20037
(202) 223-4700

June 2025

This Exhibit describes the methods used to calculate the simultaneous import limits for the FRCC in the 2027 study year.

Load Flow Cases

We utilize four load flow cases. For the summer of 2027, we use an FPL 2024 planning case for 2027 for Vandolah in the DEF BAA. FPL also provided a second planning case for summer 2027 with the additional transmission facilities to connect Vandolah to the FPL transmission system and have Vandolah part of the FPL area instead of in the DEF area. For winter 2027/28 we also use an FPL planning model for Vandolah in the DEF BAA. FPL also provided a second planning case for winter 2027/28 with the additional transmission facilities to connect Vandolah to the FPL transmission system and have Vandolah part of the FPL area instead of in the DEF area.

Areas and Subsystems

The areas in the load flow cases do not provide a one-to-one correspondence to balancing authority areas in the FRCC. For example, some merchant generation facilities have separate areas in the load flow cases. Based upon interconnections and input from FPL, we grouped areas into subsystems to match the balancing authority areas in the FRCC.

Net Interchange

The net interchange for each of the eight importing balancing authority areas is the calculated net interchange for the model subsystems that comprise the balancing authority area.

Subsystems Scaling

All importing subsystems were scaled for imports. The corresponding first tier exporting areas were scaled for export including off-line generation.

Monitored Elements

The studies monitored all transmission lines in the region in the kV range of 69 kV to 500 kV. This range is greater than OASIS practices, which mainly monitor transmission lines greater than 100 kV. However, this difference has no material significance. There are no transmission lines greater than 500 kV in the region, and none of the binding transmission lines establishing First Contingency Incremental Transfer Capability ("FCITC") values are below 100 kV. So, the results are consistent with OASIS practices and prior SIL studies accepted by the Commission.

Contingencies

The SIL calculations consider all single element contingencies in the region, including generator outages. This is more inclusive than OASIS practices which specify a specific set of contingencies. However, as a robustness check, Commission staff often have tested all single contingencies as the study here does. Although, like here, those studies at times apparently show lower limits due to a broader set of contingencies, those apparent lower limits typically are handled by operating guides so that it is only the smaller set of contingencies that define the actual FCITC. Here, the base case overloads are subject to operating guides and are not the limiting elements in practice or in regional planning studies. Once again, the results are consistent with ATC practices and SIL studies for Florida previously accepted by the Commission.

Operating Guides and Base Case Overloads

No base case overloads were found in the summer studies. Contingent base case overloads were found in the winter studies for transfers from TEC to FMPP and transfers from DEF to FPL, SOCO, and TAL. These are known transmission issues in the region and subject to fixes. In the case of the transfers from TEC to FMPP, the Pebble Dale to Crews Lake 230 kV line overloads. The first to guides result in other overloads. The solution was to turn off Polk CT2 and ramp up Bayside CT4, CT5, and CT6 to match the lost output. For the other transfers, the Arch to Haile Tap 230 kV transmission line has a contingent base case overload. The solution is to ramp up Suwanee P1&2 to their maximum capacity and ramp down Crystal River 5 by a comparable amount.

Exclusions

The study does not use exclusion data.

Model Solution

The models were loaded and solved using TARA v23.01.

Study Transfers

We tested transfers up to 10,000 MW with a limit of 20 reported violations for each transfer.

Limiting Element Selection

Per FRCC practice for ATC calculations, we select the lowest FCITC rating with a power transfer distribution factor (DFAX in the TARA software) equal to or greater than 5%, the standard OASIS practice in Florida.

Transmission Reliability Margin

The FRCC is a reserve sharing region. To ensure the ability to meet this obligation, most transmission-owning utilities in the FRCC reserve sufficient transmission capability from firm transmission service for each utility to export its reserve obligation to each interconnected utility.[1] In addition, Duke Energy

[1] All transmission service reservations less than 24-hours in the FRCC are non-firm transmission service. TRM is not reserved for non-firm transmission service.

Florida, LLC (DEF, or FPC) also reserves Tallahassee's requirements for its exports to the rest of Florida. FPL has a different procedure for calculating TRM, which is described in its "FPL Transmission Reliability Margin Implementation Document."[2] We use the TRM values that were posted on the OASIS Archive for FPL on June 5, 2025. We calculated the median TRM values, by season, between FPL and its first-tier BAs. We used these for export values for FPL. For the other utilities, including Duke Energy Florida (DEF or FPC) in the FRCC, we used the Participant Contingency Reserve Requirement effective September 1, 2023. The supporting documents are provided in the workpapers. We also calculated the TRM from the importing side, which is the Participant's Largest Amended Generation Unit Capability in the BAA less the reserve obligation for that BAA.[3] We then take the maximum of the TRM on the exporting side and the TRM on the importing side for the TRM value for the SIL calculations. Table JM-7-1 shows the resulting TRM calculated for each destination BAA by season.

2 Effective July 2020. Available on the FPL OASIS web site, https://www.oasis.oati.com/FPL/index.html.

3 The Participant's Largest Amended Generation Unit Capability (PLAGUC) may be less than an entire combined-cycle unit. For example, TEC's largest unit is the 1083 MW Polk 2 CC unit, but its largest amended generation unit capability is 542 MW. This represents a trip of a combustion turbine and the steam unit at Polk 2 CC, which assumes that the remaining combustion turbines at Polk 2 CC would continue to operate in such a situation. The values for each utility were approved by the FRCC and are provided in the workpapers. When a new unit resulted in a changed PLAGUC, we changed the PLAGUC with the commercial online date of the unit.

Table JM-7-1 — TRM Values for FRCC

BAA	TRM
FMPP	933
FPC	1,115
FPL	895
GVL	798
JEA	752
SEC	1,051
TAL	253
TEC	1,133

To implement the TRM in the SIL values, we added Row 5b to Table 1 to include the TRM value. We modified Row 6 to equal Row 4 (Total Simultaneous Transfer Capability) less Row 5 and Row 5b. All other formulas in Table 1 are the same as the standard Table 1.

Calculating SIL Values

The study uses standard Table 1 and Table 2 practices to calculate SIL Values (provided in confidential workpapers). Per Secretariat's customary practice, the firm transmission reservations are added back to the SIL values. The firm transmission reservations are then placed into a priority transfer file, so that transmission customers' energy (up to the firm reservations) is moved to the destination market. The remaining SIL, the amount to be allocated pro-rata in the PASS program, matches SIL values at the bottom of Table 1.

Spring/Fall SIL Values

In other matters, either historical spring & fall cases or summer "low load" costs have been used to estimate Spring & Fall First-Contingency Incremental Transfer Capabilities. The proffered summer low load cases studied solar at full output. Given the low load levels and maximum solar output, the cases produce many base case contingent overloads that cannot be resolved by operating guides. Accordingly, the study does not use these cases. Instead, the

Spring/Fall values are the average of the Summer and Winter Values. This is consistent with other DPT practices. For example, Summer and Winter generation capacities are averaged for the Spring/Fall capacity values.

FPL/Vandolah

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,303	576	25.0	0	0.0	-97	1,491
SF_P	33.94	1,115	92	8.3	69	6.2	1,418	200	14.1	69	4.9	-624	1,643
SF_OP	31.48	1,010	83	8.2	0	0.0	1,258	171	13.6	0	0.0	-740	1,923
SUM_T1	62.32	1,434	0	0.0	0	0.0	1,661	55	3.3	0	0.0	-496	1,745
SUM_T10	55.27	1,432	0	0.0	0	0.0	1,660	62	3.7	0	0.0	-503	1,744
SUM_P	38.52	806	0	0.0	0	0.0	1,032	31	3.0	0	0.0	-1,687	3,131
SUM_OP	32.67	767	0	0.0	0	0.0	994	20	2.0	0	0.0	-2,085	3,206
WIN_T10	49.33	2,190	373	17.0	0	0.0	3,175	679	21.4	0	0.0	223	1,499
WIN_P	34.68	1,633	328	20.1	180	11.0	1,766	419	23.7	180	10.2	-2	1,641
WIN_OP	34.71	2,022	608	30.1	370	18.3	2,507	920	36.7	370	14.7	112	2,058

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	48.45	560	317	56.7	0	0.0	560	317	56.7	0	0.0	0	3,978
SF_OP	33.06	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	40.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	73.55	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	52.21	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	39.78	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	42.84	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	52.81	923	358	38.7	0	0.0	923	358	38.7	0	0.0	0	2,820
WIN_OP	44.06	1,027	358	34.8	0	0.0	1,027	358	34.8	0	0.0	0	2,664

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	8.2	0	0.0	,93	3,206	81.4	0	0.0	481	6,722
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,692	3,046	82.5	0	0.0	489	6,909
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

FPL/Vandolah

Scenario: 2.0 Base Case

Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	88	22	24.5	3	2.9	75	20	26.2	0	0.4	85	1,195
SF_P	81.80	187	29	15.3	7	3.7	173	25	14.4	6	3.3	402	3,557
SF_OP	57.53	91	30	32.9	6	7.0	78	26	33.8	5	6.7	42	1,667
SUM_T1	54.00	112	10	9.3	0	0.0	96	9	9.3	0	0.0	-3	914
SUM_T10	42.68	112	16	14.1	0	0.0	96	14	14.0	0	0.0	-4	1,346
SUM_P	73.13	113	38	33.5	9	8.0	96	35	36.2	5	5.5	151	1,596
SUM_OP	29.96	111	15	13.7	0	0.0	95	13	13.7	0	0.0	-1	1,210
WIN_T10	76.88	174	22	12.9	1	0.5	162	18	11.1	1	0.5	530	4,728
WIN_P	68.04	68	27	39.8	2	3.7	57	22	38.9	2	3.6	-59	1,854
WIN_OP	67.84	75	22	28.7	3	4.6	63	18	27.7	3	4.5	-12	1,602

Scenario: 2.0 Base Case

Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	411	102	24.8	0	0.0	370	94	25.3	0	0.0	46	1,132
SF_P	37.56	348	54	15.5	0	0.0	306	47	15.4	0	0.0	-17	1,358
SF_OP	30.38	345	44	12.8	0	0.0	304	38	12.7	0	0.0	-12	1,232
SUM_T1	63.06	603	99	16.4	0	0.0	594	115	19.4	0	0.0	73	846
SUM_T10	53.28	580	88	15.2	0	0.0	571	87	15.2	0	0.0	-1	765
SUM_P	47.96	533	174	32.6	0	0.0	525	171	32.6	0	0.0	-2	1,486
SUM_OP	36.63	530	22	4.2	0	0.0	521	22	4.2	0	0.0	-1	1,082
WIN_T10	58.66	224	61	27.1	0	0.0	149	29	19.3	0	0.0	364	1,895
WIN_P	47.82	165	88	53.5	0	0.0	91	42	46.8	0	0.0	-463	2,607
WIN_OP	46.85	163	63	38.8	2	1.3	88	30	34.5	1	1.2	-134	1,791

Scenario: 2.0 Base Case

Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	37.74	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	36.45	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	62.95	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	64.11	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	53.12	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	41.87	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	40.13	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	49.97	476	0	0.0	0	0.0	476	0	0.0	0	0.0	0	8,683
WIN_OP	40.48	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	12,706	797	6.3	2	0.0	12,706	795	6.3	2	0.0	0	579
SF_P	42.16	13,161	765	5.8	2	0.0	13,161	764	5.8	2	0.0	0	788
SF_OP	37.05	10,238	465	4.5	0	0.0	10,238	465	4.5	0	0.0	0	630
SUM_T1	74.81	13,118	1,045	8.0	66	0.5	13,118	1,167	8.9	46	0.4	13	657
SUM_T10	71.21	13,267	1,036	7.8	224	1.7	13,268	1,165	8.8	203	1.5	13	643
SUM_P	47.16	12,806	886	6.9	1	0.0	12,806	886	6.9	1	0.0	0	678
SUM_OP	44.00	13,175	712	5.4	1	0.0	13,175	712	5.4	1	0.0	0	962
WIN_T10	55.36	17,139	456	2.7	108	0.6	17,139	456	2.7	108	0.6	0	1,030
WIN_P	39.34	12,283	364	3.0	1	0.0	12,283	363	3.0	1	0.0	0	874
WIN_OP	37.22	10,509	222	2.1	0	0.0	10,509	222	2.1	0	0.0	0	704

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	279	20	7.2	18	6.5	139	9	6.5	0	0.0	532	1,350
SF_P	51.25	307	24	7.9	25	8.2	184	9	5.0	21	11.3	338	1,122
SF_OP	40.97	246	36	14.7	27	11.1	123	15	12.4	21	17.3	46	999
SUM_T1	83.59	234	11	4.7	18	7.6	215	13	6.1	0	0.0	54	902
SUM_T10	70.24	216	11	5.2	0	0.0	215	14	6.3	0	0.0	-2	984
SUM_P	54.42	201	4	2.2	0	0.0	200	4	2.2	0	0.0	1	1,053
SUM_OP	40.77	179	2	1.0	0	0.0	178	2	1.0	0	0.0	-1	1,395
WIN_T10	60.28	401	50	12.5	0	0.0	154	2	1.3	0	0.0	3,631	4,770
WIN_P	48.96	508	6	1.2	20	4.0	260	0	0.1	18	6.9	3,594	5,256
WIN_OP	38.28	306	3	1.1	0	0.0	59	0	0.2	0	0.0	2,084	3,027

Scenario: 2.0 Base Case
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	2,168	210	9.7	0	0.0	2,585	447	17.3	0	0.0	-278	1,753
SF_P	50.99	2,803	272	9.7	186	6.6	3,224	272	8.4	354	11.0	-658	2,668
SF_OP	38.34	2,375	282	11.9	0	0.0	2,694	282	10.5	0	0.0	-461	2,636
SUM_T1	78.55	2,817	518	18.4	0	0.0	3,158	756	24.0	0	0.0	2	1,643
SUM_T10	67.92	2,807	549	19.5	0	0.0	3,148	788	25.0	0	0.0	14	1,675
SUM_P	55.21	3,236	600	18.5	0	0.0	3,527	600	17.0	0	0.0	-301	2,310
SUM_OP	39.17	2,677	608	22.7	0	0.0	2,916	608	20.8	0	0.0	-158	1,932
WIN_T10	50.54	2,338	241	10.3	0	0.0	3,233	267	8.3	0	0.0	-2,445	3,260
WIN_P	47.80	3,099	271	8.7	5	0.2	3,991	478	12.0	95	2.4	-2,461	4,147
WIN_OP	38.34	2,866	258	9.0	0	0.0	3,764	279	7.4	0	0.0	-2,482	3,888

FPL/Vandolah

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	2,305	576	25.0	0	0.0	133	1,525
SF_P	37.33	1,730	86	5.0	636	36.8	2,032	162	8.0	636	31.3	-510	1,841
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,973	657	22.1	928	31.2	-596	1,959
SUM_T1	68.55	1,434	0	0.0	0	0.0	1,661	61	3.7	0	0.0	-498	1,743
SUM_T10	60.80	1,434	0	0.0	0	0.0	1,661	69	4.2	0	0.0	-495	1,746
SUM_P	42.37	1,032	0	0.0	0	0.0	1,259	50	4.0	0	0.0	-975	2,281
SUM_OP	35.94	767	0	0.0	0	0.0	994	12	1.3	0	0.0	-1,946	3,345
WIN_T10	54.26	2,324	363	15.6	0	0.0	3,310	539	16.3	0	0.0	206	1,427
WIN_P	38.15	1,632	263	16.1	180	11.0	1,929	416	21.6	180	9.3	6	1,843
WIN_OP	38.18	2,790	574	20.6	370	13.3	3,436	902	26.3	370	10.8	-20	1,693

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	53.30	639	317	49.7	0	0.0	639	317	49.7	0	0.0	0	3,259
SF_OP	36.37	480	317	66.1	0	0.0	480	317	66.1	0	0.0	0	5,280
SUM_T1	44.01	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_T10	80.91	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	57.43	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	43.76	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	47.12	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	58.09	1,016	358	35.2	0	0.0	1,016	358	35.2	0	0.0	0	2,623
WIN_OP	48.47	1,164	358	30.7	0	0.0	1,164	358	30.7	0	0.0	0	2,821

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,945	3,306	66.8	0	0.0	267	4,758
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,686	8,305	85.7	0	0.0	57	7,417
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,970	6,656	83.5	0	0.0	172	7,023
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	3,938	3,206	81.4	0	0.0	481	6,722
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,692	3,046	82.5	0	0.0	489	6,909
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,726	6,084	90.5	0	0.0	157	8,215
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,676	6,204	92.9	0	0.0	122	8,653
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	9,317	7,745	83.1	0	0.0	-77	6,964
WIN_P	42.83	12,693	11,138	87.8	0	0.0	12,501	10,946	87.6	0	0.0	-32	7,694
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,207	10,668	87.4	91	0.7	-14	7,657

FPL/Vandolah

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	88	19	21.9	3	3.1	74	17	23.4	1	0.9	71	1,351
SF_P	89.98	186	27	14.7	6	3.5	173	24	13.7	5	3.1	401	3,562
SF_OP	63.28	91	27	29.5	7	8.1	78	24	30.4	6	7.8	29	1,556
SUM_T1	59.40	113	23	20.2	0	0.0	96	22	22.4	0	0.0	63	987
SUM_T10	46.95	112	15	13.5	0	0.0	96	13	13.5	0	0.0	-3	1,130
SUM_P	80.44	208	34	16.2	8	4.0	191	31	16.3	5	2.6	356	2,841
SUM_OP	32.96	111	15	13.2	0	0.0	95	12	13.2	0	0.0	-1	1,129
WIN_T10	84.57	174	20	11.5	1	0.6	162	16	9.9	1	0.5	530	4,736
WIN_P	74.84	177	24	13.5	3	1.9	166	19	11.7	3	1.7	528	4,815
WIN_OP	74.62	184	20	11.0	3	1.8	172	16	9.5	3	1.6	535	4,994

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	411	98	23.9	0	0.0	370	90	24.3	0	0.0	41	1,064
SF_P	41.32	349	226	64.6	0	0.0	308	195	63.4	0	0.0	-144	4,158
SF_OP	33.42	346	137	39.6	0	0.0	305	116	38.2	0	0.0	-93	1,938
SUM_T1	69.37	604	112	18.6	0	0.0	595	126	21.1	0	0.0	76	882
SUM_T10	58.61	604	143	23.7	0	0.0	595	157	26.3	0	0.0	109	1,080
SUM_P	52.76	578	189	32.6	0	0.0	570	186	32.6	0	0.0	-3	1,420
SUM_OP	40.29	531	221	41.6	0	0.0	522	217	41.6	0	0.0	-2	2,086
WIN_T10	64.53	224	58	25.7	0	0.0	149	27	18.3	0	0.0	377	1,884
WIN_P	52.60	178	72	40.3	0	0.0	104	34	33.2	0	0.0	-299	1,642
WIN_OP	51.54	163	56	34.7	2	1.1	88	27	30.9	1	1.0	-104	1,681

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	41.51	145	0	0.0	0	0.0	145	0	0.0	0	0.0	0	4,941
SF_OP	40.10	269	0	0.0	0	0.0	269	0	0.0	0	0.0	0	8,400
SUM_T1	69.25	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	70.52	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	58.43	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	46.06	250	0	0.0	0	0.0	250	0	0.0	0	0.0	0	8,150
WIN_T10	44.14	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	54.97	619	0	0.0	0	0.0	619	0	0.0	0	0.0	0	8,973
WIN_OP	44.53	877	0	0.0	0	0.0	877	0	0.0	0	0.0	0	9,668

FPL/Vandolah

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	13,442	793	5.9	2	0.0	13,714	1,064	7.8	2	0.0	4	589
SF_P	46.38	15,847	790	5.0	4	0.0	15,847	789	5.0	4	0.0	0	1,120
SF_OP	40.76	13,455	612	4.5	78	0.6	13,594	751	5.5	78	0.6	-8	877
SUM_T1	82.29	13,320	1,045	7.8	68	0.5	13,321	1,157	8.7	46	0.3	12	643
SUM_T10	78.33	13,725	1,036	7.5	231	1.7	13,726	1,153	8.4	201	1.5	11	622
SUM_P	51.88	14,516	889	6.1	1	0.0	14,516	889	6.1	1	0.0	0	963
SUM_OP	48.40	14,446	709	4.9	83	0.6	14,446	864	6.0	17	0.1	10	1,275
WIN_T10	60.90	19,897	456	2.3	112	0.6	19,897	456	2.3	112	0.6	0	1,231
WIN_P	43.27	16,598	547	3.3	1	0.0	16,598	547	3.3	1	0.0	0	1,239
WIN_OP	40.94	15,177	412	2.7	171	1.1	15,177	412	2.7	171	1.1	0	1,027

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	279	22	7.8	21	7.5	156	10	6.2	18	11.4	362	1,183
SF_P	56.38	307	35	11.5	26	8.6	184	16	8.5	20	10.9	320	1,085
SF_OP	45.07	322	36	11.1	27	8.3	199	16	8.1	20	10.1	766	1,829
SUM_T1	91.95	234	11	4.7	18	7.6	215	13	6.0	0	0.0	53	886
SUM_T10	77.26	234	12	4.9	18	7.6	215	14	6.3	0	0.0	55	919
SUM_P	59.86	219	12	5.5	18	8.4	201	15	7.3	0	0.0	28	771
SUM_OP	44.85	197	10	5.1	18	9.1	196	10	5.1	18	9.1	-1	923
WIN_T10	66.31	401	51	12.6	0	0.0	154	2	1.3	0	0.0	3,640	4,768
WIN_P	53.86	508	46	9.1	19	3.7	260	2	0.7	18	6.8	3,560	5,253
WIN_OP	42.11	428	52	12.0	22	5.1	181	2	1.2	18	9.9	3,943	5,410

Scenario: 2.1 Base Case, Price +10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	2,174	214	9.8	0	0.0	2,591	451	17.4	0	0.0	-275	1,729
SF_P	56.09	3,177	262	8.3	256	8.1	3,596	427	11.9	302	8.4	-690	3,062
SF_OP	42.17	2,375	265	11.2	289	12.2	2,794	464	16.6	327	11.7	-593	2,498
SUM_T1	86.41	2,817	515	18.3	0	0.0	3,158	752	23.8	0	0.0	-1	1,635
SUM_T10	74.71	2,807	550	19.6	4	0.1	3,148	789	25.1	0	0.0	15	1,676
SUM_P	60.73	3,446	585	17.0	120	3.5	3,786	842	22.2	0	0.0	-128	2,313
SUM_OP	43.09	2,677	602	22.5	0	0.0	2,916	602	20.7	0	0.0	-157	1,921
WIN_T10	55.59	2,572	184	7.2	0	0.0	3,469	247	7.1	0	0.0	-2,139	2,954
WIN_P	52.58	3,099	265	8.6	5	0.2	3,990	430	10.8	74	1.8	-2,483	4,123
WIN_OP	42.17	2,866	250	8.7	10	0.3	3,759	380	10.1	120	3.2	-2,526	3,840

FPL/Vandolah

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	2,302	424	18.4	0	0.0	-308	1,258
SF_P	30.55	1,046	53	5.1	0	0.0	1,246	75	6.0	0	0.0	-618	1,895
SF_OP	28.33	817	44	5.3	0	0.0	945	53	5.6	0	0.0	-780	2,730
SUM_T1	56.09	1,432	0	0.0	0	0.0	1,659	45	2.7	0	0.0	-502	1,745
SUM_T10	49.74	1,432	0	0.0	0	0.0	1,659	32	2.0	0	0.0	-535	1,712
SUM_P	34.67	806	0	0.0	0	0.0	1,033	38	3.6	0	0.0	-1,812	3,006
SUM_OP	29.40	557	0	0.0	0	0.0	784	26	3.3	0	0.0	-4,169	4,442
WIN_T10	44.40	2,190	399	18.2	0	0.0	3,175	684	21.5	0	0.0	203	1,525
WIN_P	31.21	1,043	72	6.9	0	0.0	1,043	72	6.9	0	0.0	0	2,490
WIN_OP	31.24	974	46	4.7	0	0.0	974	46	4.7	0	0.0	0	2,676

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	43.61	519	317	61.1	0	0.0	519	317	61.1	0	0.0	0	4,563
SF_OP	29.75	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	36.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	66.19	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	46.99	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	35.80	196	0	0.0	0	0.0	196	0	0.0	0	0.0	0	8,289
WIN_T10	38.56	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	47.53	820	358	43.6	0	0.0	820	358	43.6	0	0.0	0	2,894
WIN_OP	39.65	823	358	43.5	0	0.0	823	358	43.5	0	0.0	0	2,948

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	895	270	30.2	0	0.0	-890	1,675
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,191	5,631	91.0	0	0.0	-49	8,288
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,236	5,731	91.9	0	0.0	-18	8,461
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	3,805	3,086	81.1	0	0.0	504	6,677
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	1,792	1,310	73.1	0	0.0	0	5,584
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,198	2,894	90.5	0	0.0	0	8,242
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,020	5,258	87.3	0	0.0	-12	7,666
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,166	9,388	92.3	0	0.0	-26	8,537
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	9,984	9,268	92.8	0	0.0	-10	8,626

FPL/Vandolah

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	88	22	25.0	3	3.0	75	20	26.7	0	0.4	88	1,183
SF_P	73.62	187	30	16.1	[illegible]	3.7	173	26	15.0	[illegible]	3.3	402	3,560
SF_OP	51.78	92	36	39.7	[illegible]	8.1	78	32	40.8	6	7.8	74	1,932
SUM_T1	48.60	112	13	11.8	0	0.0	96	11	11.8	0	0.0	-3	1,014
SUM_T10	38.41	112	18	16.4	0	0.0	96	16	16.4	0	0.0	-4	1,586
SUM_P	65.82	113	44	39.3	6	5.0	96	41	42.5	2	2.1	235	2,037
SUM_OP	26.96	111	15	13.7	0	0.0	95	13	13.7	0	0.0	-1	1,210
WIN_T10	69.19	65	25	38.9	0	0.0	53	20	38.2	0	0.0	-44	1,915
WIN_P	61.24	68	33	48.2	2	2.4	57	27	47.2	1	2.4	-84	2,442
WIN_OP	61.06	75	24	31.5	3	3.5	63	19	30.4	2	3.4	-17	1,661

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	411	104	25.4	0	0.0	370	87	23.4	0	0.0	-51	1,051
SF_P	33.80	347	55	15.8	0	0.0	306	48	15.7	0	0.0	-18	1,412
SF_OP	27.34	345	46	13.2	0	0.0	304	40	13.1	0	0.0	-14	1,317
SUM_T1	56.75	603	104	17.3	0	0.0	594	108	18.1	0	0.0	22	797
SUM_T10	47.95	535	50	9.3	0	0.0	526	49	9.3	0	0.0	-1	913
SUM_P	43.16	533	151	28.3	0	0.0	524	148	28.3	0	0.0	-2	1,332
SUM_OP	32.97	529	43	8.2	0	0.0	521	42	8.2	0	0.0	-1	959
WIN_T10	52.79	176	72	40.8	0	0.0	102	34	33.7	0	0.0	-301	1,697
WIN_P	43.04	165	106	63.9	0	0.0	91	51	55.9	0	0.0	-739	3,533
WIN_OP	42.17	163	74	45.3	1	0.8	88	35	40.2	1	0.7	-223	2,120

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	33.97	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	32.81	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	56.66	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	57.70	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	47.81	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	37.68	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	36.12	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	44.97	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	8,207
WIN_OP	36.43	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	11,947	796	6.7	2	0.0	11,947	791	6.6	2	0.0	0	571
SF_P	37.94	9,664	617	6.4	2	0.0	9,664	615	6.4	2	0.0	0	675
SF_OP	33.35	9,572	428	4.5	0	0.0	9,572	428	4.5	0	0.0	0	791
SUM_T1	67.33	12,836	1,052	8.2	1	0.0	12,836	1,163	9.1	1	0.0	13	671
SUM_T10	64.09	12,802	1,047	8.2	1	0.0	12,802	1,164	9.1	1	0.0	14	674
SUM_P	42.44	10,604	840	7.9	1	0.0	10,604	840	7.9	1	0.0	0	560
SUM_OP	39.60	10,529	718	6.8	0	0.0	10,529	718	6.8	0	0.0	0	620
WIN_T10	49.82	14,197	459	3.2	0	0.0	14,197	459	3.2	0	0.0	0	780
WIN_P	35.41	9,384	283	3.0	1	0.0	9,384	283	3.0	1	0.0	0	808
WIN_OP	33.50	8,067	218	2.7	0	0.0	8,067	216	2.7	0	0.0	0	861

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	261	15	5.6	0	0.0	139	7	5.0	0	0.0	470	1,378
SF_P	46.13	289	12	4.2	0	0.1	166	5	3.0	0	0.1	430	1,227
SF_OP	36.87	228	4	1.6	0	0.0	105	2	1.4	0	0.0	23	890
SUM_T1	75.23	216	11	5.1	0	0.0	215	13	6.1	0	0.0	-1	932
SUM_T10	63.22	216	6	2.9	0	0.1	216	9	4.2	0	0.1	-6	912
SUM_P	48.98	202	5	2.6	0	0.1	201	5	2.6	0	0.1	2	854
SUM_OP	36.69	180	3	1.8	0	0.1	179	3	1.8	0	0.1	0	983
WIN_T10	54.25	401	40	9.9	0	0.0	154	2	1.0	0	0.0	3,480	4,783
WIN_P	44.06	403	9	2.2	0	0.1	156	0	0.2	0	0.0	3,138	4,555
WIN_OP	34.45	279	5	1.8	0	0.1	33	0	0.6	0	0.0	1,608	3,588

Scenario: 2.2 Base Case, Price -10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	1,931	213	11.0	0	0.0	2,293	208	9.1	0	0.0	-282	1,956
SF_P	45.89	2,626	282	10.7	0	0.0	2,926	282	9.6	0	0.0	-501	3,047
SF_OP	34.51	2,376	246	10.3	0	0.0	2,476	245	9.9	0	0.0	-133	3,033
SUM_T1	70.69	2,747	514	18.7	0	0.0	3,087	753	24.4	0	0.0	26	1,587
SUM_T10	61.13	2,800	543	19.4	0	0.0	3,141	790	25.2	0	0.0	22	1,700
SUM_P	49.69	3,197	614	19.2	0	0.0	3,488	614	17.6	0	0.0	-306	2,387
SUM_OP	35.25	1,044	50	4.8	0	0.0	1,044	50	4.8	0	0.0	0	2,608
WIN_T10	45.49	2,338	228	9.8	0	0.0	3,236	266	8.2	0	0.0	-2,448	3,250
WIN_P	43.02	2,888	261	9.0	0	0.0	3,667	289	7.9	0	0.0	-2,239	4,157
WIN_OP	34.51	540	263	48.7	0	0.0	1,245	286	22.9	0	0.0	-1,150	2,189

FPL/Vandolah

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	13,298	195	1.5	8,077	60.7	13,499	497	3.7	7,506	55.6	-584	3,511
SF_P	33.94	8,913	112	1.3	5,538	62.1	9,875	474	4.8	5,538	56.1	-725	3,450
SF_OP	31.48	7,121	112	1.6	4,300	60.4	8,093	482	6.0	4,300	53.1	-830	3,156
SUM_T1	62.32	14,675	114	0.8	9,486	64.6	14,308	201	1.4	8,895	62.2	-293	4,234
SUM_T10	55.27	14,084	114	0.8	8,897	63.2	13,717	204	1.5	8,306	60.6	-301	4,068
SUM_P	38.52	11,044	114	1.0	6,922	62.7	11,265	194	1.7	6,922	61.4	-163	4,135
SUM_OP	32.67	6,335	114	1.8	3,586	56.6	6,555	178	2.7	3,586	54.7	-235	3,436
WIN_T10	49.33	10,978	140	1.3	5,964	54.3	12,634	556	4.4	5,965	47.2	-785	2,743
WIN_P	34.68	8,204	139	1.7	4,891	59.6	9,834	560	5.7	4,891	49.7	-1,100	2,941
WIN_OP	34.71	9,198	146	1.6	5,050	54.9	10,850	571	5.3	5,053	46.6	-895	2,669

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	48.45	2,666	24	0.9	1	0.0	2,666	24	0.9	1	0.0	0	5,022
SF_OP	33.06	1,812	24	1.3	0	0.0	1,812	24	1.3	0	0.0	0	4,817
SUM_T1	40.01	2,411	31	1.3	2	0.1	2,411	31	1.3	2	0.1	0	4,650
SUM_T10	73.55	3,492	31	0.9	2	0.0	3,492	31	0.9	2	0.0	0	4,728
SUM_P	52.21	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	39.78	2,424	31	1.3	0	0.0	2,424	31	1.3	0	0.0	0	4,992
WIN_T10	42.84	2,904	28	1.0	0	0.0	2,904	28	1.0	0	0.0	0	5,038
WIN_P	52.81	3,032	28	0.9	0	0.0	3,032	28	0.9	0	0.0	0	5,097
WIN_OP	44.06	2,861	28	1.0	0	0.0	2,861	28	1.0	0	0.0	0	5,022

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	30,951	28,608	92.4	494	1.6	30,469	28,348	93.0	354	1.2	112	8,667
SF_P	37.63	29,246	27,059	92.5	306	1.0	28,833	26,867	93.2	221	0.8	121	8,694
SF_OP	34.12	25,065	22,913	91.4	490	2.0	24,767	22,837	92.2	362	1.5	144	8,517
SUM_T1	60.20	35,433	33,870	95.6	0	0.0	36,017	34,454	95.7	0	0.0	14	9,156
SUM_T10	48.08	33,932	32,455	95.6	0	0.0	34,515	33,038	95.7	0	0.0	14	9,169
SUM_P	44.35	30,793	29,333	95.3	0	0.0	30,940	29,480	95.3	0	0.0	4	9,086
SUM_OP	38.09	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	40.13	30,928	28,595	92.5	295	1.0	30,656	28,323	92.4	295	1.0	-12	8,547
WIN_P	38.94	28,785	26,664	92.6	135	0.5	28,593	26,472	92.6	135	0.5	-9	8,584
WIN_OP	37.51	26,251	24,124	91.9	347	1.3	26,171	24,044	91.9	347	1.3	-4	8,455

FPL/Vandolah

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	546	26	4.8	8	1.4	532	22	4.2	6	1.1	246	5,423
SF_P	81.80	363	27	7.5	8	2.1	349	23	6.6	6	1.8	242	3,860
SF_OP	57.53	267	28	10.3	8	2.8	253	24	9.3	6	2.5	206	2,816
SUM_T1	54.00	526	44	8.4	11	2.1	510	38	7.4	9	1.8	236	4,448
SUM_T10	42.68	308	57	18.4	5	1.8	292	48	16.5	5	1.6	154	2,643
SUM_P	73.13	529	35	6.6	10	1.9	513	30	5.9	8	1.6	240	4,480
SUM_OP	29.96	199	30	14.9	0	0.0	183	25	13.8	0	0.0	260	3,244
WIN_T10	76.88	377	20	5.3	5	1.2	366	16	4.4	4	1.0	250	4,474
WIN_P	68.04	268	22	8.1	5	1.7	257	18	6.8	4	1.5	240	3,353
WIN_OP	67.84	268	19	7.2	5	1.8	256	16	6.1	4	1.5	240	3,357

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	2,558	108	4.2	25	1.0	2,517	95	3.8	21	0.8	227	7,344
SF_P	37.56	1,009	166	16.4	4	0.4	967	143	14.8	3	0.4	324	5,051
SF_OP	30.38	841	103	12.2	0	0.0	800	89	11.1	0	0.0	317	4,362
SUM_T1	63.06	2,876	168	5.8	38	1.3	2,868	167	5.8	37	1.3	37	6,393
SUM_T10	53.28	2,169	178	8.2	29	1.3	2,160	175	8.1	28	1.3	40	5,581
SUM_P	47.96	1,857	188	10.1	18	0.9	1,848	185	10.0	17	0.9	43	5,376
SUM_OP	36.63	1,052	184	17.4	0	0.0	1,043	180	17.3	0	0.0	29	3,281
WIN_T10	58.66	1,911	47	2.5	8	0.4	1,838	23	1.2	4	0.2	629	8,471
WIN_P	47.82	1,489	56	3.8	5	0.3	1,415	27	1.9	2	0.2	827	8,789
WIN_OP	46.85	1,484	49	3.3	10	0.6	1,410	24	1.7	5	0.3	834	8,814

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	2,626	0	0.0	0	0.0	2,626	0	0.0	0	0.0	0	9,451
SF_P	37.74	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	36.45	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	62.95	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	64.11	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	53.12	2,619	0	0.0	0	0.0	2,619	0	0.0	0	0.0	0	9,480
SUM_OP	41.87	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	40.13	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	49.97	2,487	0	0.0	0	0.0	2,487	0	0.0	0	0.0	0	9,663
WIN_OP	40.48	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	47,746	652	1.4	1,761	3.7	47,743	650	1.4	1,761	3.7	0	4,014
SF_P	42.16	42,006	602	1.4	1,737	4.1	42,004	600	1.4	1,737	4.1	0	3,871
SF_OP	37.05	35,446	428	1.2	1,789	5.0	35,446	427	1.2	1,789	5.0	0	4,007
SUM_T1	74.81	55,390	901	1.6	1,092	2.0	55,390	920	1.7	1,072	1.9	0	4,393
SUM_T10	71.21	55,089	884	1.6	1,079	2.0	55,090	903	1.6	1,074	2.0	0	4,414
SUM_P	47.16	46,884	724	1.5	1,027	2.2	46,884	724	1.5	1,027	2.2	0	4,362
SUM_OP	44.00	43,583	577	1.3	958	2.2	43,583	577	1.3	958	2.2	0	4,365
WIN_T10	55.36	52,967	325	0.6	1,944	3.7	52,966	324	0.6	1,944	3.7	0	4,074
WIN_P	39.34	41,977	359	0.9	1,678	4.0	41,976	358	0.9	1,678	4.0	0	4,055
WIN_OP	37.22	38,073	221	0.6	1,884	4.9	38,072	220	0.6	1,884	4.9	0	4,014

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	883	36	4.1	41	4.7	777	15	2.0	27	3.5	1,454	6,693
SF_P	51.25	873	42	4.8	45	5.2	771	17	2.2	29	3.8	1,438	6,784
SF_OP	40.97	760	40	5.3	43	5.6	657	17	2.5	28	4.3	1,704	6,998
SUM_T1	83.59	916	10	1.1	34	3.7	915	11	1.2	33	3.6	10	6,021
SUM_T10	70.24	916	10	1.1	34	3.7	915	11	1.2	33	3.6	10	6,028
SUM_P	54.42	896	10	1.2	30	3.4	895	10	1.2	30	3.4	11	6,241
SUM_OP	40.77	699	10	1.4	31	4.4	698	10	1.4	31	4.4	12	5,866
WIN_T10	60.28	1,048	43	4.1	46	4.4	839	2	0.2	19	2.3	2,953	8,394
WIN_P	48.96	1,036	23	2.3	51	4.9	844	1	0.1	19	2.3	2,735	8,337
WIN_OP	38.28	816	23	2.8	46	5.6	623	1	0.2	19	3.0	3,430	8,538

Scenario: 1.0 Base Case
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	6,929	240	3.5	781	11.3	7,346	278	3.8	990	13.5	-534	5,055
SF_P	50.99	6,396	241	3.8	792	12.4	6,814	240	3.5	1,076	15.8	-522	4,923
SF_OP	38.34	5,587	242	4.3	784	14.0	6,006	241	4.0	1,077	17.9	-539	4,702
SUM_T1	78.55	8,461	622	7.3	829	9.8	8,804	649	7.4	983	11.2	-346	4,804
SUM_T10	67.92	8,163	621	7.6	824	10.1	8,506	650	7.6	972	11.4	-347	4,663
SUM_P	55.21	7,602	624	8.2	840	11.1	7,946	624	7.9	1,030	13.0	-360	4,663
SUM_OP	39.17	6,546	627	9.6	815	12.5	6,891	627	9.1	986	14.3	-357	4,156
WIN_T10	50.54	6,237	161	2.6	568	9.1	7,124	259	3.6	884	12.4	-1,463	5,327
WIN_P	47.80	6,326	201	3.2	578	9.1	7,204	263	3.7	975	13.5	-1,419	5,418
WIN_OP	38.34	5,784	174	3.0	566	9.8	6,675	258	3.9	981	14.7	-1,454	5,127

FPL/Vandolah

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	13,858	190	1.4	8,635	62.3	14,059	492	3.5	8,064	57.4	-579	3,677
SF_P	37.33	10,902	112	1.0	6,592	60.5	11,870	480	4.0	6,593	55.5	-602	3,492
SF_OP	34.63	10,716	112	1.0	6,246	58.3	11,550	492	4.3	6,104	52.9	-643	3,297
SUM_T1	68.55	14,810	114	0.8	9,622	65.0	14,443	199	1.4	9,030	62.5	-291	4,271
SUM_T10	60.80	14,558	114	0.8	9,369	64.4	14,190	200	1.4	8,778	61.9	-295	4,201
SUM_P	42.37	11,327	114	1.0	6,922	61.1	11,551	212	1.8	6,922	59.9	-155	3,998
SUM_OP	35.94	9,461	114	1.2	5,191	54.9	9,685	202	2.1	5,192	53.6	-159	3,434
WIN_T10	54.26	11,362	140	1.2	6,345	55.8	13,018	551	4.2	6,346	48.7	-797	2,859
WIN_P	38.15	9,455	140	1.5	5,416	57.3	11,097	563	5.1	5,418	48.8	-927	2,826
WIN_OP	38.18	9,731	143	1.5	5,050	51.9	11,388	562	4.9	5,052	44.4	-820	2,596

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	53.30	2,745	24	0.9	1	0.0	2,745	24	0.9	1	0.0	0	4,939
SF_OP	36.37	2,015	24	1.2	0	0.0	2,015	24	1.2	0	0.0	0	5,124
SUM_T1	44.01	2,416	31	1.3	2	0.1	2,416	31	1.3	2	0.1	0	4,631
SUM_T10	80.91	3,507	31	0.9	2	0.0	3,507	31	0.9	2	0.0	0	4,740
SUM_P	57.43	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	43.76	2,623	31	1.2	0	0.0	2,623	31	1.2	0	0.0	0	5,244
WIN_T10	47.12	3,008	28	0.9	0	0.0	3,008	28	0.9	0	0.0	0	5,143
WIN_P	58.09	3,124	28	0.9	0	0.0	3,124	28	0.9	0	0.0	0	5,005
WIN_OP	48.47	2,998	28	0.9	0	0.0	2,998	28	0.9	0	0.0	0	5,161

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	31,999	29,493	92.2	626	2.0	32,387	29,797	92.0	693	2.1	-30	8,478
SF_P	41.39	30,664	28,166	91.9	483	1.6	30,980	28,398	91.7	535	1.7	-34	8,416
SF_OP	37.53	25,672	23,490	91.5	590	2.3	26,243	23,978	91.4	652	2.5	-24	8,365
SUM_T1	66.22	35,433	33,870	95.6	0	0.0	36,017	34,454	95.7	0	0.0	14	9,156
SUM_T10	52.89	33,932	32,455	95.6	0	0.0	34,515	33,038	95.7	0	0.0	14	9,169
SUM_P	48.79	31,163	29,703	95.3	0	0.0	31,746	30,286	95.4	0	0.0	16	9,108
SUM_OP	41.90	27,370	26,092	95.3	0	0.0	27,954	26,676	95.4	0	0.0	18	9,114
WIN_T10	44.14	31,315	28,806	92.0	348	1.1	31,043	28,534	91.9	348	1.1	-13	8,461
WIN_P	42.83	30,575	28,240	92.4	300	1.0	30,383	28,048	92.3	300	1.0	-9	8,533
WIN_OP	41.26	28,028	25,727	91.8	270	1.0	27,948	25,647	91.8	270	1.0	-4	8,434

FPL/Vandolah

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	546	26	4.7	7	1.4	532	22	4.1	6	1.1	246	5,423
SF_P	89.98	362	27	7.4	8	2.1	349	23	6.5	6	1.8	241	3,861
SF_OP	63.28	267	26	9.9	8	2.9	253	23	8.9	6	2.6	207	2,808
SUM_T1	59.40	530	40	7.6	9	1.7	514	35	6.7	8	1.5	237	4,466
SUM_T10	46.95	526	56	10.6	8	1.6	510	48	9.3	7	1.4	232	4,443
SUM_P	80.44	624	34	5.4	10	1.6	608	29	4.8	8	1.3	239	5,120
SUM_OP	32.96	200	42	21.1	0	0.0	184	36	19.6	0	0.0	253	3,257
WIN_T10	84.57	377	19	5.1	4	1.2	366	16	4.3	4	1.0	250	4,474
WIN_P	74.84	378	21	5.5	5	1.3	366	17	4.6	4	1.1	248	4,467
WIN_OP	74.62	377	19	5.0	5	1.2	366	15	4.2	4	1.0	248	4,476

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	2,558	105	4.1	25	1.0	2,517	92	3.7	22	0.9	227	7,342
SF_P	41.32	1,168	150	12.8	6	0.5	1,127	130	11.5	5	0.4	328	5,566
SF_OP	33.42	847	143	16.9	0	0.0	806	124	15.4	0	0.0	301	4,358
SUM_T1	69.37	2,876	164	5.7	38	1.3	2,868	163	5.7	37	1.3	37	6,391
SUM_T10	58.61	2,878	174	6.0	40	1.4	2,869	173	6.0	39	1.3	37	6,388
SUM_P	52.76	2,163	177	8.2	34	1.6	2,154	174	8.1	34	1.6	40	5,587
SUM_OP	40.29	1,213	185	15.3	16	1.3	1,204	182	15.1	16	1.3	37	3,745
WIN_T10	64.53	1,911	47	2.4	8	0.4	1,838	22	1.2	4	0.2	629	8,471
WIN_P	52.60	1,868	52	2.8	10	0.5	1,794	25	1.4	5	0.3	676	8,898
WIN_OP	51.54	1,483	47	3.1	9	0.6	1,410	22	1.6	4	0.3	833	8,816

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	2,762	0	0.0	0	0.0	2,762	0	0.0	0	0.0	0	9,477
SF_P	41.51	2,211	0	0.0	0	0.0	2,211	0	0.0	0	0.0	0	9,440
SF_OP	40.10	2,175	0	0.0	0	0.0	2,175	0	0.0	0	0.0	0	9,730
SUM_T1	69.25	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	70.52	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	58.43	2,895	0	0.0	0	0.0	2,895	0	0.0	0	0.0	0	9,529
SUM_OP	46.06	2,685	0	0.0	0	0.0	2,685	0	0.0	0	0.0	0	9,755
WIN_T10	44.14	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	54.97	2,630	0	0.0	0	0.0	2,630	0	0.0	0	0.0	0	9,681
WIN_OP	44.53	2,729	0	0.0	0	0.0	2,729	0	0.0	0	0.0	0	9,862

FPL/Vandolah

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	48,202	650	1.3	1,770	3.7	48,200	698	1.4	1,770	3.7	1	3,965
SF_P	46.38	44,226	602	1.4	1,706	3.9	44,224	600	1.4	1,706	3.9	0	4,001
SF_OP	40.76	39,197	446	1.1	1,710	4.4	39,196	466	1.2	1,710	4.4	0	3,837
SUM_T1	82.29	55,621	901	1.6	1,077	1.9	55,621	920	1.7	1,058	1.9	0	4,364
SUM_T10	78.33	55,548	884	1.6	1,068	1.9	55,548	903	1.6	1,066	1.9	0	4,375
SUM_P	51.88	48,601	723	1.5	968	2.0	48,601	723	1.5	968	2.0	0	4,446
SUM_OP	48.40	45,318	574	1.3	923	2.0	45,318	601	1.3	921	2.0	0	4,501
WIN_T10	60.90	54,692	325	0.6	1,852	3.4	54,691	324	0.6	1,852	3.4	0	4,220
WIN_P	43.27	46,754	353	0.8	1,866	4.0	46,753	353	0.8	1,866	4.0	0	3,928
WIN_OP	40.94	42,454	314	0.7	1,899	4.5	42,453	314	0.7	1,899	4.5	0	3,919

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	884	35	4.0	43	4.9	778	15	1.9	28	3.6	1,461	6,681
SF_P	56.38	880	39	4.4	41	4.7	774	16	2.1	27	3.5	1,475	6,734
SF_OP	45.07	846	38	4.6	40	4.8	740	16	2.2	27	3.6	1,652	7,265
SUM_T1	91.95	916	10	1.1	33	3.6	916	11	1.2	33	3.6	10	6,019
SUM_T10	77.26	916	10	1.1	34	3.7	915	11	1.2	33	3.6	10	6,027
SUM_P	59.86	897	10	1.1	30	3.4	896	11	1.2	29	3.3	10	6,227
SUM_OP	44.85	785	10	1.3	29	3.7	784	10	1.3	29	3.7	12	6,195
WIN_T10	66.31	1,048	42	4.0	46	4.4	839	2	0.2	19	2.3	2,953	8,394
WIN_P	53.86	1,049	47	4.5	51	4.9	844	2	0.2	19	2.3	2,859	8,326
WIN_OP	42.11	935	47	5.0	50	5.3	728	2	0.3	19	2.6	3,337	8,723

Scenario: 1.1 Base Case, Price +10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	6,935	239	3.4	777	11.2	7,352	275	3.7	985	13.4	-533	5,044
SF_P	56.09	6,771	240	3.5	779	11.5	7,189	279	3.9	986	13.7	-542	5,024
SF_OP	42.17	5,588	241	4.3	805	14.4	6,007	293	4.9	1,037	17.3	-566	4,678
SUM_T1	86.41	8,461	621	7.3	830	9.8	8,804	648	7.4	985	11.2	-346	4,804
SUM_T10	74.71	8,161	621	7.6	829	10.2	8,504	648	7.6	983	11.6	-346	4,666
SUM_P	60.73	7,811	621	8.0	830	10.6	8,154	654	8.0	978	12.0	-345	4,507
SUM_OP	43.09	6,549	626	9.6	832	12.7	6,894	626	9.1	1,015	14.7	-355	4,158
WIN_T10	55.59	6,472	134	2.1	565	8.7	7,361	255	3.5	834	11.3	-1,367	5,087
WIN_P	52.58	6,326	164	2.6	570	9.0	7,213	259	3.6	888	12.3	-1,456	5,375
WIN_OP	42.17	5,785	142	2.4	568	9.8	6,676	260	3.9	899	13.5	-1,493	5,085

FPL/Vandolah

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	12,944	194	1.5	7,723	59.7	13,146	500	3.8	7,152	54.4	-586	3,402
SF_P	30.55	6,486	112	1.7	4,789	73.8	7,444	472	6.3	4,789	64.3	-1,256	4,305
SF_OP	28.33	3,706	112	3.0	1,466	39.6	4,647	468	10.1	1,466	31.5	-781	1,843
SUM_T1	56.09	14,049	114	0.8	8,862	63.1	13,682	204	1.5	8,271	60.4	-302	4,057
SUM_T10	49.74	13,611	114	0.8	8,424	61.9	13,244	205	1.6	7,833	59.1	-307	3,928
SUM_P	34.67	7,869	114	1.5	5,033	64.0	8,088	187	2.3	5,033	62.2	-230	4,179
SUM_OP	29.40	2,895	114	4.0	1,511	52.2	3,113	174	5.6	1,511	48.5	-407	2,827
WIN_T10	44.40	10,591	141	1.3	5,610	53.0	12,247	556	4.5	5,611	45.8	-770	2,641
WIN_P	31.21	4,786	141	2.9	2,868	59.9	6,245	549	8.8	2,868	45.9	-1,362	2,579
WIN_OP	31.24	5,474	135	2.5	2,502	45.7	6,566	549	8.4	2,502	38.1	-812	2,287

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	2,589	24	0.9	1	0.0	2,589	24	0.9	1	0.0	0	4,896
SF_P	43.61	2,577	24	0.9	1	0.0	2,577	24	0.9	1	0.0	0	4,920
SF_OP	29.75	1,534	24	1.6	0	0.0	1,534	24	1.6	0	0.0	0	4,318
SUM_T1	36.01	2,299	31	1.3	2	0.1	2,299	31	1.3	2	0.1	0	4,502
SUM_T10	66.19	3,464	31	0.9	2	0.0	3,464	31	0.9	2	0.0	0	4,706
SUM_P	46.99	3,118	31	1.0	1	0.0	3,118	31	1.0	1	0.0	0	4,806
SUM_OP	35.80	2,196	31	1.4	0	0.0	2,196	31	1.4	0	0.0	0	4,711
WIN_T10	38.56	2,558	28	1.1	0	0.0	2,558	28	1.1	0	0.0	0	4,673
WIN_P	47.53	2,928	28	0.9	0	0.0	2,928	28	0.9	0	0.0	0	4,992
WIN_OP	39.65	2,658	28	1.0	0	0.0	2,658	28	1.0	0	0.0	0	4,808

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	29,244	27,078	92.6	382	1.3	28,763	26,818	93.2	275	1.0	119	8,705
SF_P	33.87	28,068	25,910	92.3	338	1.2	27,655	25,718	93.0	248	0.9	125	8,660
SF_OP	30.71	24,812	22,886	92.2	0	0.0	24,726	22,810	92.3	0	0.0	3	8,526
SUM_T1	54.18	35,300	33,750	95.6	0	0.0	35,884	34,334	95.7	0	0.0	13	9,160
SUM_T10	43.27	32,615	31,303	96.0	0	0.0	32,615	31,303	96.0	0	0.0	0	9,217
SUM_P	39.92	28,219	27,096	96.0	0	0.0	28,219	27,096	96.0	0	0.0	0	9,228
SUM_OP	34.28	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	36.12	28,408	26,305	92.6	23	0.1	28,136	26,033	92.5	23	0.1	-13	8,574
WIN_P	35.05	28,773	26,667	92.7	117	0.4	28,581	26,475	92.6	117	0.4	-9	8,593
WIN_OP	33.76	26,236	24,124	92.0	21	0.1	26,156	24,044	91.9	21	0.1	-4	8,466

FPL/Vandolah

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	546	26	4.8	8	1.4	532	22	4.2	6	1.1	246	5,423
SF_P	73.62	363	28	7.6	8	2.1	349	24	6.7	6	1.9	242	3,861
SF_OP	51.78	267	30	11.1	8	3.0	254	25	10.0	7	2.7	205	2,816
SUM_T1	48.60	526	54	10.3	9	1.7	510	46	9.0	8	1.5	233	4,444
SUM_T10	38.41	306	55	18.0	4	1.3	290	47	16.2	3	1.1	158	2,655
SUM_P	65.82	530	37	7.0	10	1.8	513	32	6.2	8	1.6	239	4,477
SUM_OP	26.96	196	52	26.3	0	0.0	181	44	24.3	0	0.0	258	3,355
WIN_T10	69.19	268	21	7.7	4	1.7	256	17	6.6	4	1.4	242	3,357
WIN_P	61.24	269	23	8.7	5	1.7	257	19	7.4	4	1.5	239	3,355
WIN_OP	61.06	268	20	7.5	4	1.7	256	16	6.4	4	1.4	240	3,359

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	2,076	114	5.5	26	1.3	2,035	99	4.9	23	1.1	255	6,780
SF_P	33.80	848	110	12.9	6	0.7	806	94	11.6	5	0.6	325	4,331
SF_OP	27.34	334	97	29.0	0	0.0	293	84	28.5	0	0.0	-43	2,541
SUM_T1	56.75	2,878	176	6.1	36	1.3	2,869	174	6.1	36	1.2	36	6,389
SUM_T10	47.95	1,544	197	12.8	10	0.6	1,535	194	12.6	10	0.6	42	4,668
SUM_P	43.16	1,378	204	14.8	4	0.3	1,369	201	14.7	4	0.3	40	4,279
SUM_OP	32.97	1,046	153	14.6	0	0.0	1,037	150	14.5	0	0.0	30	3,280
WIN_T10	52.79	1,864	50	2.7	9	0.5	1,791	24	1.3	4	0.2	680	8,914
WIN_P	43.04	1,007	62	6.2	2	0.2	934	30	3.2	1	0.1	1,102	8,209
WIN_OP	42.17	842	50	6.0	10	1.2	768	24	3.2	5	0.6	1,263	7,894

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	2,354	0	0.0	0	0.0	2,354	0	0.0	0	0.0	0	9,388
SF_P	33.97	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	32.81	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	56.66	2,701	0	0.0	0	0.0	2,701	0	0.0	0	0.0	0	9,254
SUM_T10	57.70	2,977	0	0.0	0	0.0	2,977	0	0.0	0	0.0	0	9,322
SUM_P	47.81	2,496	0	0.0	0	0.0	2,496	0	0.0	0	0.0	0	9,455
SUM_OP	37.68	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	36.12	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	44.97	2,353	0	0.0	0	0.0	2,353	0	0.0	0	0.0	0	9,644
WIN_OP	36.43	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	45,893	654	1.4	1,771	3.9	45,890	652	1.4	1,771	3.9	0	3,951
SF_P	37.94	37,710	610	1.6	1,786	4.7	37,707	607	1.6	1,786	4.7	0	3,900
SF_OP	33.35	35,280	431	1.2	1,813	5.1	35,279	430	1.2	1,813	5.1	0	4,008
SUM_T1	67.33	53,909	901	1.7	1,038	1.9	53,909	920	1.7	1,037	1.9	0	4,343
SUM_T10	64.09	52,989	885	1.7	1,040	2.0	52,990	905	1.7	1,034	2.0	0	4,296
SUM_P	42.44	44,530	722	1.6	1,164	2.6	44,530	722	1.6	1,164	2.6	0	4,329
SUM_OP	39.60	40,743	577	1.4	1,095	2.7	40,743	577	1.4	1,095	2.7	0	4,354
WIN_T10	49.82	50,334	327	0.6	1,940	3.9	50,333	326	0.6	1,940	3.9	0	3,996
WIN_P	35.41	39,070	363	0.9	1,672	4.3	39,067	360	0.9	1,672	4.3	1	3,906
WIN_OP	33.50	35,584	225	0.6	1,573	4.4	35,584	224	0.6	1,573	4.4	0	4,028

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	882	38	4.3	42	4.7	777	16	2.0	27	3.5	1,450	6,698
SF_P	46.13	870	22	2.5	49	5.6	770	9	1.2	31	4.0	1,422	6,809
SF_OP	36.87	677	23	3.4	48	7.1	578	9	1.6	30	5.2	1,724	6,738
SUM_T1	75.23	916	10	1.1	34	3.7	915	11	1.2	33	3.7	10	6,028
SUM_T10	63.22	913	10	1.1	32	3.4	912	11	1.2	31	3.4	10	6,059
SUM_P	48.98	888	10	1.2	33	3.8	887	10	1.2	33	3.8	10	6,363
SUM_OP	36.69	459	10	2.2	30	6.6	458	10	2.2	30	6.6	12	4,455
WIN_T10	54.25	1,042	44	4.3	52	5.0	838	2	0.2	19	2.3	2,886	8,399
WIN_P	44.06	960	29	3.0	52	5.4	758	1	0.2	19	2.5	2,970	8,152
WIN_OP	34.45	571	25	4.4	50	8.7	378	1	0.3	19	5.1	4,083	7,667

Scenario: 1.2 Base Case, Price -10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	6,692	241	3.6	801	12.0	7,110	239	3.4	1,089	15.3	-552	5,324
SF_P	45.89	6,219	243	3.9	793	12.7	6,637	242	3.6	1,094	16.5	-545	5,085
SF_OP	34.51	5,585	241	4.3	759	13.6	6,003	240	4.0	998	16.6	-552	4,704
SUM_T1	70.69	8,392	622	7.4	820	9.8	8,735	650	7.4	966	11.1	-348	4,767
SUM_T10	61.13	8,156	623	7.6	835	10.2	8,499	655	7.7	988	11.6	-346	4,676
SUM_P	49.69	7,559	629	8.3	839	11.1	7,903	629	8.0	1,028	13.0	-366	4,716
SUM_OP	35.25	4,493	632	14.1	748	16.6	4,838	632	13.1	869	18.0	-338	3,093
WIN_T10	45.49	6,236	197	3.2	576	9.2	7,119	258	3.6	1,013	14.2	-1,414	5,383
WIN_P	43.02	6,113	219	3.6	557	9.1	6,994	260	3.7	921	13.2	-1,428	5,315
WIN_OP	34.51	3,454	211	6.1	557	16.1	4,334	261	6.0	899	20.7	-1,731	4,012

FPL/Vandolah

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,303	434	18.8	0	0.0	-330	1,258
SF_P	33.94	1,115	92	8.3	69	6.2	1,418	200	14.1	69	4.9	-624	1,643
SF_OP	31.48	1,010	83	8.2	0	0.0	1,258	171	13.6	0	0.0	-740	1,923
SUM_T1	62.32	1,434	0	0.0	0	0.0	1,661	50	3.0	0	0.0	-498	1,743
SUM_T10	55.27	1,432	0	0.0	0	0.0	1,660	56	3.4	0	0.0	-506	1,741
SUM_P	38.52	806	0	0.0	0	0.0	1,032	31	3.0	0	0.0	-1,687	3,131
SUM_OP	32.67	767	0	0.0	0	0.0	994	20	2.0	0	0.0	-2,085	3,206
WIN_T10	49.33	2,190	373	17.0	0	0.0	3,175	679	21.4	0	0.0	223	1,499
WIN_P	34.68	1,633	328	20.1	180	11.0	1,766	419	23.7	180	10.2	-2	1,641
WIN_OP	34.71	2,022	608	30.1	370	18.3	2,507	920	36.7	370	14.7	112	2,058

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	48.45	560	317	56.7	0	0.0	560	317	56.7	0	0.0	0	3,978
SF_OP	33.06	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	40.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	73.55	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	52.21	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	39.78	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	42.84	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	52.81	923	358	38.7	0	0.0	923	358	38.7	0	0.0	0	2,820
WIN_OP	44.06	1,027	358	34.8	0	0.0	1,027	358	34.8	0	0.0	0	2,664

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,937	2,915	74.0	0	0.0	-611	5,630
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,690	2,754	74.6	0	0.0	-685	5,736
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,919	5,278	89.2	0	0.0	47	7,990
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

FPL/Vandolah

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	88	22	24.5	3	2.9	75	19	24.9	0	0.4	22	1,132
SF_P	81.80	187	29	15.3	7	3.7	173	24	14.0	6	3.3	391	3,545
SF_OP	57.53	91	30	32.9	6	7.0	78	26	32.8	5	6.7	-23	1,602
SUM_T1	54.00	112	10	9.3	0	0.0	96	9	9.3	0	0.0	-3	914
SUM_T10	42.68	112	16	14.1	0	0.0	96	14	14.0	0	0.0	-4	1,346
SUM_P	73.13	113	38	33.5	9	8.0	96	33	34.7	5	5.5	51	1,497
SUM_OP	29.96	111	15	13.7	0	0.0	95	13	13.7	0	0.0	-1	1,210
WIN_T10	76.88	174	22	12.9	1	0.5	162	18	11.1	1	0.5	530	4,728
WIN_P	68.04	68	27	39.8	2	3.7	57	22	38.9	2	3.6	-59	1,854
WIN_OP	67.84	75	22	28.7	3	4.6	63	18	27.7	3	4.5	-12	1,602

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	411	102	24.8	0	0.0	370	88	23.7	0	0.0	-32	1,054
SF_P	37.56	348	54	15.5	0	0.0	306	47	15.4	0	0.0	-17	1,358
SF_OP	30.38	345	44	12.8	0	0.0	304	38	12.7	0	0.0	-12	1,232
SUM_T1	63.06	603	99	16.4	0	0.0	594	104	17.5	0	0.0	9	781
SUM_T10	53.28	580	88	15.2	0	0.0	571	87	15.2	0	0.0	-1	765
SUM_P	47.96	533	174	32.6	0	0.0	525	171	32.6	0	0.0	-2	1,486
SUM_OP	36.63	530	22	4.2	0	0.0	521	22	4.2	0	0.0	-1	1,082
WIN_T10	58.66	224	61	27.1	0	0.0	149	29	19.3	0	0.0	364	1,895
WIN_P	47.82	165	88	53.5	0	0.0	91	42	46.8	0	0.0	-463	2,607
WIN_OP	46.85	163	63	38.8	2	1.3	88	30	34.5	1	1.2	-134	1,791

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	37.74	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	36.45	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	62.95	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	64.11	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	53.12	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	41.87	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	40.13	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	49.97	476	0	0.0	0	0.0	476	0	0.0	0	0.0	0	8,683
WIN_OP	40.48	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	12,706	797	6.3	2	0.0	12,706	795	6.3	2	0.0	0	579
SF_P	42.16	13,161	765	5.8	2	0.0	13,161	764	5.8	2	0.0	0	788
SF_OP	37.05	10,238	465	4.5	0	0.0	10,238	465	4.5	0	0.0	0	630
SUM_T1	74.81	13,118	1,045	8.0	66	0.5	13,118	1,106	8.4	46	0.4	5	649
SUM_T10	71.21	13,267	1,036	7.8	224	1.7	13,268	1,101	8.3	203	1.5	5	635
SUM_P	47.16	12,806	886	6.9	1	0.0	12,806	886	6.9	1	0.0	0	678
SUM_OP	44.00	13,175	712	5.4	1	0.0	13,175	712	5.4	1	0.0	0	962
WIN_T10	55.36	17,139	456	2.7	108	0.6	17,139	456	2.7	108	0.6	0	1,030
WIN_P	39.34	12,283	364	3.0	1	0.0	12,283	363	3.0	1	0.0	0	874
WIN_OP	37.22	10,509	222	2.1	0	0.0	10,509	222	2.1	0	0.0	0	704

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	279	20	7.2	18	6.5	139	8	6.0	0	0.0	526	1,344
SF_P	51.25	307	24	7.9	25	8.2	184	9	5.0	21	11.3	338	1,122
SF_OP	40.97	246	36	14.7	27	11.1	123	15	12.4	21	17.3	46	999
SUM_T1	83.59	234	11	4.7	18	7.6	215	12	5.6	0	0.0	48	896
SUM_T10	70.24	216	11	5.2	0	0.0	215	12	5.8	0	0.0	-9	978
SUM_P	54.42	201	4	2.2	0	0.0	200	4	2.2	0	0.0	1	1,053
SUM_OP	40.77	179	2	1.0	0	0.0	178	2	1.0	0	0.0	-1	1,395
WIN_T10	60.28	401	50	12.5	0	0.0	154	2	1.3	0	0.0	3,631	4,770
WIN_P	48.96	508	6	1.2	20	4.0	260	0	0.1	18	6.9	3,594	5,256
WIN_OP	38.28	306	3	1.1	0	0.0	59	0	0.2	0	0.0	2,084	3,027

Scenario: 2.0 Base Case Mitigation Case
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	2,168	210	9.7	0	0.0	2,585	328	12.7	0	0.0	-395	1,636
SF_P	50.99	2,803	272	9.7	186	6.6	3,224	272	8.4	354	11.0	-658	2,668
SF_OP	38.34	2,375	282	11.9	0	0.0	2,694	282	10.5	0	0.0	-461	2,636
SUM_T1	78.55	2,817	518	18.4	0	0.0	3,158	637	20.2	0	0.0	-150	1,491
SUM_T10	67.92	2,807	549	19.5	0	0.0	3,148	669	21.2	0	0.0	-147	1,514
SUM_P	55.21	3,236	600	18.5	0	0.0	3,527	600	17.0	0	0.0	-301	2,310
SUM_OP	39.17	2,677	608	22.7	0	0.0	2,916	608	20.8	0	0.0	-158	1,932
WIN_T10	50.54	2,338	241	10.3	0	0.0	3,233	267	8.3	0	0.0	-2,445	3,260
WIN_P	47.80	3,099	271	8.7	5	0.2	3,991	478	12.0	95	2.4	-2,461	4,147
WIN_OP	38.34	2,866	258	9.0	0	0.0	3,764	279	7.4	0	0.0	-2,482	3,888

FPL/Vandolah

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	2,305	434	18.8	0	0.0	-99	1,293
SF_P	37.33	1,730	86	5.0	636	36.8	2,032	162	8.0	636	31.3	-510	1,841
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,973	657	22.1	928	31.2	-596	1,959
SUM_T1	68.55	1,434	0	0.0	0	0.0	1,661	56	3.4	0	0.0	-501	1,741
SUM_T10	60.80	1,434	0	0.0	0	0.0	1,661	64	3.8	0	0.0	-498	1,743
SUM_P	42.37	1,032	0	0.0	0	0.0	1,259	50	4.0	0	0.0	-975	2,281
SUM_OP	35.94	767	0	0.0	0	0.0	994	12	1.3	0	0.0	-1,946	3,345
WIN_T10	54.26	2,324	363	15.6	0	0.0	3,310	539	16.3	0	0.0	206	1,427
WIN_P	38.15	1,632	263	16.1	180	11.0	1,929	416	21.6	180	9.3	6	1,843
WIN_OP	38.18	2,790	574	20.6	370	13.3	3,436	902	26.3	370	10.8	-20	1,693

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	53.30	639	317	49.7	0	0.0	639	317	49.7	0	0.0	0	3,259
SF_OP	36.37	480	317	66.1	0	0.0	480	317	66.1	0	0.0	0	5,280
SUM_T1	44.01	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_T10	80.91	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	57.43	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	43.76	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	47.12	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	58.09	1,016	358	35.2	0	0.0	1,016	358	35.2	0	0.0	0	2,623
WIN_OP	48.47	1,164	358	30.7	0	0.0	1,164	358	30.7	0	0.0	0	2,821

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,945	3,025	61.2	0	0.0	-428	4,062
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,686	8,163	84.3	0	0.0	-189	7,171
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,970	6,374	80.0	0	0.0	-392	6,459
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	3,937	2,915	74.0	0	0.0	-611	5,630
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,690	2,754	74.6	0	0.0	-685	5,736
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,725	5,793	86.2	0	0.0	-586	7,471
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,675	5,913	88.6	0	0.0	-648	7,883
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	9,317	7,745	83.1	0	0.0	-77	6,964
WIN_P	42.83	12,693	11,138	87.8	0	0.0	12,501	10,946	87.6	0	0.0	-32	7,694
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,207	10,668	87.4	91	0.7	-14	7,657

FPL/Vandolah

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	88	19	21.9	3	3.1	74	17	22.3	1	0.9	20	1,301
SF_P	89.98	186	27	14.7	6	3.5	173	23	13.3	5	3.1	391	3,552
SF_OP	63.28	91	27	29.5	7	8.1	78	23	29.5	6	7.8	-23	1,504
SUM_T1	59.40	113	23	20.2	0	0.0	96	22	22.4	0	0.0	63	987
SUM_T10	46.95	112	15	13.5	0	0.0	96	13	13.5	0	0.0	-3	1,130
SUM_P	80.44	208	34	16.2	8	4.0	191	30	15.6	5	2.6	336	2,821
SUM_OP	32.96	111	15	13.2	0	0.0	95	12	13.2	0	0.0	-1	1,129
WIN_T10	84.57	174	20	11.5	1	0.6	162	16	9.9	1	0.5	530	4,736
WIN_P	74.84	177	24	13.5	3	1.9	166	19	11.7	3	1.7	528	4,815
WIN_OP	74.62	184	20	11.0	3	1.8	172	16	9.5	3	1.6	535	4,994

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	411	98	23.9	0	0.0	370	85	22.9	0	0.0	-22	1,000
SF_P	41.32	349	226	64.6	0	0.0	308	195	63.4	0	0.0	-144	4,158
SF_OP	33.42	346	137	39.6	0	0.0	305	116	38.2	0	0.0	-93	1,938
SUM_T1	69.37	604	112	18.6	0	0.0	595	116	19.4	0	0.0	11	817
SUM_T10	58.61	604	143	23.7	0	0.0	595	145	24.5	0	0.0	17	987
SUM_P	52.76	578	189	32.6	0	0.0	570	186	32.6	0	0.0	-3	1,420
SUM_OP	40.29	531	221	41.6	0	0.0	522	217	41.6	0	0.0	-2	2,086
WIN_T10	64.53	224	58	25.7	0	0.0	149	27	18.3	0	0.0	377	1,884
WIN_P	52.60	178	72	40.3	0	0.0	104	34	33.2	0	0.0	-299	1,642
WIN_OP	51.54	163	56	34.7	2	1.1	88	27	30.9	1	1.0	-104	1,681

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	41.51	145	0	0.0	0	0.0	145	0	0.0	0	0.0	0	4,941
SF_OP	40.10	269	0	0.0	0	0.0	269	0	0.0	0	0.0	0	8,400
SUM_T1	69.25	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	70.52	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	58.43	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	46.06	250	0	0.0	0	0.0	250	0	0.0	0	0.0	0	8,150
WIN_T10	44.14	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	54.97	619	0	0.0	0	0.0	619	0	0.0	0	0.0	0	8,973
WIN_OP	44.53	877	0	0.0	0	0.0	877	0	0.0	0	0.0	0	9,668

FPL/Vandolah

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	13,442	793	5.9	2	0.0	13,714	928	6.8	2	0.0	-10	576
SF_P	46.38	15,847	790	5.0	4	0.0	15,847	789	5.0	4	0.0	0	1,120
SF_OP	40.76	13,455	612	4.5	78	0.6	13,594	751	5.5	78	0.6	-8	877
SUM_T1	82.29	13,320	1,045	7.8	68	0.5	13,321	1,102	8.3	46	0.3	5	636
SUM_T10	78.33	13,725	1,036	7.5	231	1.7	13,726	1,095	8.0	201	1.5	4	615
SUM_P	51.88	14,516	889	6.1	1	0.0	14,516	889	6.1	1	0.0	0	963
SUM_OP	48.40	14,446	709	4.9	83	0.6	14,446	786	5.4	17	0.1	4	1,269
WIN_T10	60.90	19,897	456	2.3	112	0.6	19,897	456	2.3	112	0.6	0	1,231
WIN_P	43.27	16,598	547	3.3	1	0.0	16,598	547	3.3	1	0.0	0	1,239
WIN_OP	40.94	15,177	412	2.7	171	1.1	15,177	412	2.7	171	1.1	0	1,027

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	279	22	7.8	21	7.5	156	9	5.8	18	11.4	358	1,179
SF_P	56.38	307	35	11.5	26	8.6	184	15	8.1	20	10.9	314	1,079
SF_OP	45.07	322	36	11.1	27	8.3	199	15	7.7	20	10.1	761	1,823
SUM_T1	91.95	234	11	4.7	18	7.6	215	12	5.6	0	0.0	47	881
SUM_T10	77.26	234	12	4.9	18	7.6	215	12	5.8	0	0.0	49	913
SUM_P	59.86	219	12	5.5	18	8.4	201	13	6.6	0	0.0	19	762
SUM_OP	44.85	197	10	5.1	18	9.1	196	10	5.1	18	9.1	-1	923
WIN_T10	66.31	401	51	12.6	0	0.0	154	2	1.3	0	0.0	3,640	4,768
WIN_P	53.86	508	46	9.1	19	3.7	260	2	0.7	18	6.8	3,560	5,253
WIN_OP	42.11	428	52	12.0	22	5.1	181	2	1.2	18	9.9	3,943	5,410

Scenario: 2.1 Base Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	2,174	214	9.8	0	0.0	2,591	332	12.8	0	0.0	-394	1,610
SF_P	56.09	3,177	262	8.3	256	8.1	3,596	345	9.6	302	8.4	-734	3,018
SF_OP	42.17	2,375	265	11.2	289	12.2	2,794	365	13.1	327	11.7	-685	2,406
SUM_T1	86.41	2,817	515	18.3	0	0.0	3,158	634	20.1	0	0.0	-151	1,485
SUM_T10	74.71	2,807	550	19.6	4	0.1	3,148	670	21.3	0	0.0	-146	1,515
SUM_P	60.73	3,446	585	17.0	120	3.5	3,786	714	18.9	0	0.0	-255	2,186
SUM_OP	43.09	2,677	602	22.5	0	0.0	2,916	602	20.7	0	0.0	-157	1,921
WIN_T10	55.59	2,572	184	7.2	0	0.0	3,469	247	7.1	0	0.0	-2,139	2,954
WIN_P	52.58	3,099	265	8.6	5	0.2	3,990	430	10.8	74	1.8	-2,483	4,123
WIN_OP	42.17	2,866	250	8.7	10	0.3	3,759	380	10.1	120	3.2	-2,526	3,840

FPL/Vandolah

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	2,302	282	12.3	0	0.0	-460	1,106
SF_P	30.55	1,046	53	5.1	0	0.0	1,246	75	6.0	0	0.0	-618	1,895
SF_OP	28.33	817	44	5.3	0	0.0	945	53	5.6	0	0.0	-780	2,730
SUM_T1	56.09	1,432	0	0.0	0	0.0	1,659	38	2.3	0	0.0	-504	1,743
SUM_T10	49.74	1,432	0	0.0	0	0.0	1,659	24	1.4	0	0.0	-537	1,710
SUM_P	34.67	806	0	0.0	0	0.0	1,033	38	3.6	0	0.0	-1,812	3,006
SUM_OP	29.40	557	0	0.0	0	0.0	784	26	3.3	0	0.0	-4,169	4,442
WIN_T10	44.40	2,190	399	18.2	0	0.0	3,175	684	21.5	0	0.0	203	1,525
WIN_P	31.21	1,043	72	6.9	0	0.0	1,043	72	6.9	0	0.0	0	2,490
WIN_OP	31.24	974	46	4.7	0	0.0	974	46	4.7	0	0.0	0	2,676

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	43.61	519	317	61.1	0	0.0	519	317	61.1	0	0.0	0	4,563
SF_OP	29.75	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	36.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	66.19	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	46.99	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	35.80	196	0	0.0	0	0.0	196	0	0.0	0	0.0	0	8,289
WIN_T10	38.56	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	47.53	820	358	43.6	0	0.0	820	358	43.6	0	0.0	0	2,894
WIN_OP	39.65	823	358	43.5	0	0.0	823	358	43.5	0	0.0	0	2,948

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	895	270	30.2	0	0.0	-890	1,675
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,191	5,631	91.0	0	0.0	-49	8,288
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,236	5,731	91.9	0	0.0	-18	8,461
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	3,804	2,795	73.5	0	0.0	-617	5,556
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	1,792	1,310	73.1	0	0.0	0	5,584
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,198	2,894	90.5	0	0.0	0	8,242
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,020	5,258	87.3	0	0.0	-12	7,666
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,166	9,388	92.3	0	0.0	-26	8,537
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	9,984	9,268	92.8	0	0.0	-10	8,626

FPL/Vandolah

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	88	22	25.0	3	3.0	75	19	25.4	0	0.4	22	1,118
SF_P	73.62	187	30	16.1	7	3.7	173	25	14.6	6	3.3	389	3,548
SF_OP	51.78	92	36	39.7	7	8.1	78	31	39.5	6	7.8	-28	1,830
SUM_T1	48.60	112	13	11.8	0	0.0	96	11	11.8	0	0.0	-3	1,014
SUM_T10	38.41	112	18	16.4	0	0.0	96	16	16.4	0	0.0	-4	1,586
SUM_P	65.82	113	44	39.3	6	5.0	96	39	40.8	2	2.1	95	1,897
SUM_OP	26.96	111	15	13.7	0	0.0	95	13	13.7	0	0.0	-1	1,210
WIN_T10	69.19	65	25	38.9	0	0.0	53	20	38.2	0	0.0	-44	1,915
WIN_P	61.24	68	33	48.2	2	2.4	57	27	47.2	1	2.4	-84	2,442
WIN_OP	61.06	75	24	31.5	3	3.5	63	19	30.4	2	3.4	-17	1,661

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	411	104	25.4	0	0.0	370	87	23.4	0	0.0	-51	1,051
SF_P	33.80	347	55	15.8	0	0.0	306	48	15.7	0	0.0	-18	1,412
SF_OP	27.34	345	46	13.2	0	0.0	304	40	13.1	0	0.0	-14	1,317
SUM_T1	56.75	603	104	17.3	0	0.0	594	108	18.1	0	0.0	22	797
SUM_T10	47.95	535	50	9.3	0	0.0	526	49	9.3	0	0.0	-1	913
SUM_P	43.16	533	151	28.3	0	0.0	524	148	28.3	0	0.0	-2	1,332
SUM_OP	32.97	529	43	8.2	0	0.0	521	42	8.2	0	0.0	-1	959
WIN_T10	52.79	176	72	40.8	0	0.0	102	34	33.7	0	0.0	-301	1,697
WIN_P	43.04	165	106	63.9	0	0.0	91	51	55.9	0	0.0	-739	3,533
WIN_OP	42.17	163	74	45.3	1	0.8	88	35	40.2	1	0.7	-223	2,120

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	33.97	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	32.81	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	56.66	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	57.70	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	47.81	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	37.68	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	36.12	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	44.97	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	8,207
WIN_OP	36.43	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	11,947	796	6.7	2	0.0	11,947	791	6.6	2	0.0	0	571
SF_P	37.94	9,664	617	6.4	2	0.0	9,664	615	6.4	2	0.0	0	675
SF_OP	33.35	9,572	428	4.5	0	0.0	9,572	428	4.5	0	0.0	0	791
SUM_T1	67.33	12,836	1,052	8.2	1	0.0	12,836	1,108	8.6	1	0.0	6	664
SUM_T10	64.09	12,802	1,047	8.2	1	0.0	12,802	1,105	8.6	1	0.0	6	666
SUM_P	42.44	10,604	840	7.9	1	0.0	10,604	840	7.9	1	0.0	0	560
SUM_OP	39.60	10,529	718	6.8	0	0.0	10,529	718	6.8	0	0.0	0	620
WIN_T10	49.82	14,197	459	3.2	0	0.0	14,197	459	3.2	0	0.0	0	780
WIN_P	35.41	9,384	283	3.0	1	0.0	9,384	283	3.0	1	0.0	0	808
WIN_OP	33.50	8,067	218	2.7	0	0.0	8,067	216	2.7	0	0.0	0	861

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	261	15	5.6	0	0.0	139	6	4.4	0	0.0	464	1,373
SF_P	46.13	289	12	4.2	0	0.1	166	5	3.0	0	0.1	430	1,227
SF_OP	36.87	228	4	1.6	0	0.0	105	2	1.4	0	0.0	23	890
SUM_T1	75.23	216	11	5.1	0	0.0	215	12	5.6	0	0.0	-7	926
SUM_T10	63.22	216	6	2.9	0	0.1	216	8	3.5	0	0.1	-10	907
SUM_P	48.98	202	5	2.6	0	0.1	201	5	2.6	0	0.1	2	854
SUM_OP	36.69	180	3	1.8	0	0.1	179	3	1.8	0	0.1	0	983
WIN_T10	54.25	401	40	9.9	0	0.0	154	2	1.0	0	0.0	3,480	4,783
WIN_P	44.06	403	9	2.2	0	0.1	156	0	0.2	0	0.0	3,138	4,555
WIN_OP	34.45	279	5	1.8	0	0.1	33	0	0.6	0	0.0	1,608	3,588

Scenario: 2.2 Base Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	1,931	213	11.0	0	0.0	2,293	208	9.1	0	0.0	-282	1,956
SF_P	45.89	2,626	282	10.7	0	0.0	2,926	282	9.6	0	0.0	-501	3,047
SF_OP	34.51	2,376	246	10.3	0	0.0	2,476	245	9.9	0	0.0	-133	3,033
SUM_T1	70.69	2,747	514	18.7	0	0.0	3,087	634	20.5	0	0.0	-133	1,428
SUM_T10	61.13	2,800	543	19.4	0	0.0	3,141	667	21.2	0	0.0	-145	1,533
SUM_P	49.69	3,197	614	19.2	0	0.0	3,488	614	17.6	0	0.0	-306	2,387
SUM_OP	35.25	1,044	50	4.8	0	0.0	1,044	50	4.8	0	0.0	0	2,608
WIN_T10	45.49	2,338	228	9.8	0	0.0	3,236	266	8.2	0	0.0	-2,448	3,250
WIN_P	43.02	2,888	261	9.0	0	0.0	3,667	289	7.9	0	0.0	-2,239	4,157
WIN_OP	34.51	540	263	48.7	0	0.0	1,245	286	22.9	0	0.0	-1,150	2,189

FPL/Vandolah

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	13,298	195	1.5	8,077	60.7	13,499	485	3.6	7,506	55.6	-584	3,510
SF_P	33.94	8,913	112	1.3	5,538	62.1	9,875	474	4.8	5,538	56.1	-725	3,450
SF_OP	31.48	7,121	112	1.6	4,300	60.4	8,093	482	6.0	4,300	53.1	-830	3,156
SUM_T1	62.32	14,675	114	0.8	9,486	64.6	14,308	200	1.4	8,895	62.2	-293	4,234
SUM_T10	55.27	14,084	114	0.8	8,897	63.2	13,717	203	1.5	8,306	60.6	-301	4,068
SUM_P	38.52	11,044	114	1.0	6,922	62.7	11,265	194	1.7	6,922	61.4	-163	4,135
SUM_OP	32.67	6,335	114	1.8	3,586	56.6	6,555	178	2.7	3,586	54.7	-235	3,436
WIN_T10	49.33	10,978	140	1.3	5,964	54.3	12,634	556	4.4	5,965	47.2	-785	2,743
WIN_P	34.68	8,204	139	1.7	4,891	59.6	9,834	560	5.7	4,891	49.7	-1,100	2,941
WIN_OP	34.71	9,198	146	1.6	5,050	54.9	10,850	571	5.3	5,053	46.6	-895	2,669

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	48.45	2,666	24	0.9	1	0.0	2,666	24	0.9	1	0.0	0	5,022
SF_OP	33.06	1,812	24	1.3	0	0.0	1,812	24	1.3	0	0.0	0	4,817
SUM_T1	40.01	2,411	31	1.3	2	0.1	2,411	31	1.3	2	0.1	0	4,650
SUM_T10	73.55	3,492	31	0.9	2	0.0	3,492	31	0.9	2	0.0	0	4,728
SUM_P	52.21	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	39.78	2,424	31	1.3	0	0.0	2,424	31	1.3	0	0.0	0	4,992
WIN_T10	42.84	2,904	28	1.0	0	0.0	2,904	28	1.0	0	0.0	0	5,038
WIN_P	52.81	3,032	28	0.9	0	0.0	3,032	28	0.9	0	0.0	0	5,097
WIN_OP	44.06	2,861	28	1.0	0	0.0	2,861	28	1.0	0	0.0	0	5,022

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	30,951	28,608	92.4	494	1.6	30,775	28,348	92.1	547	1.8	-57	8,498
SF_P	37.63	29,246	27,059	92.5	306	1.0	29,137	26,867	92.2	338	1.2	-57	8,516
SF_OP	34.12	25,065	22,913	91.4	490	2.0	25,073	22,837	91.1	539	2.1	-59	8,314
SUM_T1	60.20	35,433	33,870	95.6	0	0.0	36,015	34,163	94.9	0	0.0	-139	9,004
SUM_T10	48.08	33,932	32,455	95.6	0	0.0	34,513	32,748	94.9	0	0.0	-145	9,010
SUM_P	44.35	30,793	29,333	95.3	0	0.0	30,940	29,480	95.3	0	0.0	4	9,086
SUM_OP	38.09	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	40.13	30,943	28,595	92.4	247	0.8	30,671	28,323	92.3	247	0.8	-12	8,539
WIN_P	38.94	28,801	26,664	92.6	132	0.5	28,609	26,472	92.5	132	0.5	-9	8,575
WIN_OP	37.51	26,267	24,124	91.8	345	1.3	26,187	24,044	91.8	345	1.3	-4	8,445

FPL/Vandolah

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	546	26	4.8	8	1.4	532	22	4.2	6	1.1	246	5,423
SF_P	81.80	363	27	7.5	8	2.1	349	23	6.6	6	1.8	241	3,860
SF_OP	57.53	267	28	10.3	8	2.8	253	23	9.2	6	2.5	204	2,814
SUM_T1	54.00	526	44	8.4	11	2.1	510	38	7.4	9	1.8	236	4,448
SUM_T10	42.68	308	57	18.4	5	1.8	292	48	16.5	5	1.6	154	2,643
SUM_P	73.13	529	35	6.6	10	1.9	513	30	5.8	8	1.6	239	4,479
SUM_OP	29.96	199	30	14.9	0	0.0	183	25	13.8	0	0.0	260	3,244
WIN_T10	76.88	377	20	5.3	5	1.2	366	16	4.4	4	1.0	250	4,474
WIN_P	68.04	268	22	8.1	5	1.7	257	18	6.8	4	1.5	240	3,353
WIN_OP	67.84	268	19	7.2	5	1.8	256	16	6.1	4	1.5	240	3,357

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	2,558	108	4.2	25	1.0	2,517	94	3.7	21	0.8	227	7,344
SF_P	37.56	1,009	166	16.4	4	0.4	967	143	14.8	3	0.4	324	5,051
SF_OP	30.38	841	103	12.2	0	0.0	800	89	11.1	0	0.0	317	4,362
SUM_T1	63.06	2,876	168	5.8	38	1.3	2,868	166	5.8	37	1.3	36	6,392
SUM_T10	53.28	2,169	178	8.2	29	1.3	2,160	175	8.1	28	1.3	40	5,581
SUM_P	47.96	1,857	188	10.1	18	0.9	1,848	185	10.0	17	0.9	43	5,376
SUM_OP	36.63	1,052	184	17.4	0	0.0	1,043	180	17.3	0	0.0	29	3,281
WIN_T10	58.66	1,911	47	2.5	8	0.4	1,838	23	1.2	4	0.2	629	8,471
WIN_P	47.82	1,489	56	3.8	5	0.3	1,415	27	1.9	2	0.2	827	8,789
WIN_OP	46.85	1,484	49	3.3	10	0.6	1,410	24	1.7	5	0.3	834	8,814

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	2,626	0	0.0	0	0.0	2,626	0	0.0	0	0.0	0	9,451
SF_P	37.74	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	36.45	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	62.95	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	64.11	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	53.12	2,619	0	0.0	0	0.0	2,619	0	0.0	0	0.0	0	9,480
SUM_OP	41.87	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	40.13	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	49.97	2,487	0	0.0	0	0.0	2,487	0	0.0	0	0.0	0	9,663
WIN_OP	40.48	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	47,746	652	1.4	1,761	3.7	47,743	650	1.4	1,761	3.7	0	4,014
SF_P	42.16	42,006	602	1.4	1,737	4.1	42,004	600	1.4	1,737	4.1	0	3,871
SF_OP	37.05	35,446	428	1.2	1,789	5.0	35,446	427	1.2	1,789	5.0	0	4,007
SUM_T1	74.81	55,390	901	1.6	1,092	2.0	55,390	910	1.6	1,072	1.9	0	4,393
SUM_T10	71.21	55,089	884	1.6	1,079	2.0	55,090	894	1.6	1,074	2.0	0	4,414
SUM_P	47.16	46,884	724	1.5	1,027	2.2	46,884	724	1.5	1,027	2.2	0	4,362
SUM_OP	44.00	43,583	577	1.3	958	2.2	43,583	577	1.3	958	2.2	0	4,365
WIN_T10	55.36	52,967	325	0.6	1,944	3.7	52,966	324	0.6	1,944	3.7	0	4,074
WIN_P	39.34	41,977	359	0.9	1,678	4.0	41,976	358	0.9	1,678	4.0	0	4,055
WIN_OP	37.22	38,073	221	0.6	1,884	4.9	38,072	220	0.6	1,884	4.9	0	4,014

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	883	36	4.1	41	4.7	777	15	1.9	27	3.5	1,454	6,693
SF_P	51.25	873	42	4.8	45	5.2	771	17	2.2	29	3.8	1,438	6,784
SF_OP	40.97	760	40	5.3	43	5.6	657	17	2.5	28	4.3	1,704	6,998
SUM_T1	83.59	916	10	1.1	34	3.7	915	10	1.1	33	3.6	10	6,021
SUM_T10	70.24	916	10	1.1	34	3.7	915	10	1.1	33	3.6	10	6,028
SUM_P	54.42	896	10	1.2	30	3.4	895	10	1.2	30	3.4	11	6,241
SUM_OP	40.77	699	10	1.4	31	4.4	698	10	1.4	31	4.4	12	5,866
WIN_T10	60.28	1,048	43	4.1	46	4.4	839	2	0.2	19	2.3	2,953	8,394
WIN_P	48.96	1,036	23	2.3	51	4.9	844	1	0.1	19	2.3	2,735	8,337
WIN_OP	38.28	816	23	2.8	46	5.6	623	1	0.2	19	3.0	3,430	8,538

Scenario: 1.0 Base Case Mitigation Case
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	6,929	240	3.5	781	11.3	7,346	258	3.5	990	13.5	-536	5,053
SF_P	50.99	6,396	241	3.8	792	12.4	6,814	240	3.5	1,076	15.8	-522	4,923
SF_OP	38.34	5,587	242	4.3	784	14.0	6,006	241	4.0	1,077	17.9	-539	4,702
SUM_T1	78.55	8,461	622	7.3	829	9.8	8,804	635	7.2	983	11.2	-349	4,802
SUM_T10	67.92	8,163	621	7.6	824	10.1	8,506	636	7.5	972	11.4	-349	4,660
SUM_P	55.21	7,602	624	8.2	840	11.1	7,946	624	7.9	1,030	13.0	-360	4,663
SUM_OP	39.17	6,546	627	9.6	815	12.5	6,891	627	9.1	986	14.3	-357	4,156
WIN_T10	50.54	6,237	161	2.6	568	9.1	7,124	259	3.6	884	12.4	-1,463	5,327
WIN_P	47.80	6,326	201	3.2	578	9.1	7,204	263	3.7	975	13.5	-1,419	5,418
WIN_OP	38.34	5,784	174	3.0	566	9.8	6,675	258	3.9	981	14.7	-1,454	5,127

FPL/Vandolah

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	13,858	190	1.4	8,635	62.3	14,059	482	3.4	8,064	57.4	-580	3,676
SF_P	37.33	10,902	112	1.0	6,592	60.5	11,870	480	4.0	6,593	55.5	-602	3,492
SF_OP	34.63	10,716	112	1.0	6,246	58.3	11,550	492	4.3	6,104	52.9	-643	3,297
SUM_T1	68.55	14,810	114	0.8	9,622	65.0	14,443	198	1.4	9,030	62.5	-291	4,271
SUM_T10	60.80	14,558	114	0.8	9,369	64.4	14,190	200	1.4	8,778	61.9	-295	4,201
SUM_P	42.37	11,327	114	1.0	6,922	61.1	11,551	212	1.8	6,922	59.9	-155	3,998
SUM_OP	35.94	9,461	114	1.2	5,191	54.9	9,685	202	2.1	5,192	53.6	-159	3,434
WIN_T10	54.26	11,362	140	1.2	6,345	55.8	13,018	551	4.2	6,346	48.7	-797	2,859
WIN_P	38.15	9,455	140	1.5	5,416	57.3	11,097	563	5.1	5,418	48.8	-927	2,826
WIN_OP	38.18	9,731	143	1.5	5,050	51.9	11,388	562	4.9	5,052	44.4	-820	2,596

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	53.30	2,745	24	0.9	1	0.0	2,745	24	0.9	1	0.0	0	4,939
SF_OP	36.37	2,015	24	1.2	0	0.0	2,015	24	1.2	0	0.0	0	5,124
SUM_T1	44.01	2,416	31	1.3	2	0.1	2,416	31	1.3	2	0.1	0	4,631
SUM_T10	80.91	3,507	31	0.9	2	0.0	3,507	31	0.9	2	0.0	0	4,740
SUM_P	57.43	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	43.76	2,623	31	1.2	0	0.0	2,623	31	1.2	0	0.0	0	5,244
WIN_T10	47.12	3,008	28	0.9	0	0.0	3,008	28	0.9	0	0.0	0	5,143
WIN_P	58.09	3,124	28	0.9	0	0.0	3,124	28	0.9	0	0.0	0	5,005
WIN_OP	48.47	2,998	28	0.9	0	0.0	2,998	28	0.9	0	0.0	0	5,161

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	31,999	29,493	92.2	626	2.0	32,386	29,516	91.1	693	2.1	-187	8,320
SF_P	41.39	30,664	28,166	91.9	483	1.6	30,979	28,257	91.2	535	1.7	-116	8,333
SF_OP	37.53	25,672	23,490	91.5	590	2.3	26,242	23,696	90.3	652	2.5	-217	8,172
SUM_T1	66.22	35,433	33,870	95.6	0	0.0	36,015	34,163	94.9	0	0.0	-139	9,004
SUM_T10	52.89	33,932	32,455	95.6	0	0.0	34,508	32,748	94.9	0	0.0	-142	9,012
SUM_P	48.79	31,163	29,703	95.3	0	0.0	31,739	29,995	94.5	0	0.0	-153	8,939
SUM_OP	41.90	27,370	26,092	95.3	0	0.0	27,947	26,385	94.4	0	0.0	-174	8,922
WIN_T10	44.14	31,315	28,806	92.0	348	1.1	31,043	28,534	91.9	348	1.1	-13	8,461
WIN_P	42.83	30,575	28,240	92.4	300	1.0	30,383	28,048	92.3	300	1.0	-9	8,533
WIN_OP	41.26	28,028	25,727	91.8	270	1.0	27,948	25,647	91.8	270	1.0	-4	8,434

FPL/Vandolah

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	546	26	4.7	7	1.3	532	22	4.1	6	1.1	245	5,422
SF_P	89.98	362	27	7.4	8	2.1	349	23	6.5	6	1.8	241	3,860
SF_OP	63.28	267	26	9.9	8	2.9	253	22	8.8	6	2.6	205	2,806
SUM_T1	59.40	530	40	7.6	9	1.7	514	35	6.7	8	1.5	237	4,466
SUM_T10	46.95	526	56	10.6	8	1.6	510	48	9.3	7	1.4	232	4,443
SUM_P	80.44	624	34	5.4	10	1.6	608	29	4.8	8	1.3	239	5,120
SUM_OP	32.96	200	42	21.1	0	0.0	184	36	19.6	0	0.0	253	3,257
WIN_T10	84.57	377	19	5.1	4	1.2	366	16	4.3	4	1.0	250	4,474
WIN_P	74.84	378	21	5.5	5	1.3	366	17	4.6	4	1.1	248	4,467
WIN_OP	74.62	377	19	5.0	5	1.2	366	15	4.2	4	1.0	248	4,476

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	2,558	105	4.1	25	1.0	2,517	92	3.6	22	0.9	227	7,342
SF_P	41.32	1,168	150	12.8	6	0.5	1,127	130	11.5	5	0.4	328	5,566
SF_OP	33.42	847	143	16.9	0	0.0	806	124	15.4	0	0.0	301	4,358
SUM_T1	69.37	2,876	164	5.7	38	1.3	2,868	162	5.6	37	1.3	36	6,390
SUM_T10	58.61	2,878	174	6.0	40	1.4	2,869	171	6.0	39	1.3	36	6,388
SUM_P	52.76	2,163	177	8.2	34	1.6	2,154	174	8.1	34	1.6	40	5,587
SUM_OP	40.29	1,213	185	15.3	16	1.3	1,204	182	15.1	16	1.3	37	3,745
WIN_T10	64.53	1,911	47	2.4	8	0.4	1,838	22	1.2	4	0.2	629	8,471
WIN_P	52.60	1,868	52	2.8	10	0.5	1,794	25	1.4	5	0.3	676	8,898
WIN_OP	51.54	1,483	47	3.1	9	0.6	1,410	22	1.6	4	0.3	833	8,816

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	2,762	0	0.0	0	0.0	2,762	0	0.0	0	0.0	0	9,477
SF_P	41.51	2,211	0	0.0	0	0.0	2,211	0	0.0	0	0.0	0	9,440
SF_OP	40.10	2,175	0	0.0	0	0.0	2,175	0	0.0	0	0.0	0	9,730
SUM_T1	69.25	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	70.52	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	58.43	2,895	0	0.0	0	0.0	2,895	0	0.0	0	0.0	0	9,529
SUM_OP	46.06	2,685	0	0.0	0	0.0	2,685	0	0.0	0	0.0	0	9,755
WIN_T10	44.14	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	54.97	2,630	0	0.0	0	0.0	2,630	0	0.0	0	0.0	0	9,681
WIN_OP	44.53	2,729	0	0.0	0	0.0	2,729	0	0.0	0	0.0	0	9,862

FPL/Vandolah

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	48,202	650	1.3	1,770	3.7	48,200	673	1.4	1,770	3.7	0	3,965
SF_P	46.38	44,226	602	1.4	1,706	3.9	44,224	600	1.4	1,706	3.9	0	4,001
SF_OP	40.76	39,197	446	1.1	1,710	4.4	39,196	466	1.2	1,710	4.4	0	3,837
SUM_T1	82.29	55,621	901	1.6	1,077	1.9	55,621	910	1.6	1,058	1.9	0	4,364
SUM_T10	78.33	55,548	884	1.6	1,068	1.9	55,548	893	1.6	1,066	1.9	0	4,375
SUM_P	51.88	48,601	723	1.5	968	2.0	48,601	723	1.5	968	2.0	0	4,446
SUM_OP	48.40	45,318	574	1.3	923	2.0	45,318	588	1.3	921	2.0	0	4,501
WIN_T10	60.90	54,692	325	0.6	1,852	3.4	54,691	324	0.6	1,852	3.4	0	4,220
WIN_P	43.27	46,754	353	0.8	1,866	4.0	46,753	353	0.8	1,866	4.0	0	3,928
WIN_OP	40.94	42,454	314	0.7	1,899	4.5	42,453	314	0.7	1,899	4.5	0	3,919

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	884	35	4.0	43	4.9	778	15	1.9	28	3.6	1,461	6,681
SF_P	56.38	880	39	4.4	41	4.7	774	16	2.1	27	3.5	1,475	6,734
SF_OP	45.07	846	38	4.6	40	4.8	740	16	2.2	27	3.6	1,652	7,265
SUM_T1	91.95	916	10	1.1	33	3.6	916	10	1.1	33	3.6	10	6,019
SUM_T10	77.26	916	10	1.1	34	3.7	915	10	1.1	33	3.6	10	6,027
SUM_P	59.86	897	10	1.1	30	3.4	896	10	1.2	29	3.3	10	6,227
SUM_OP	44.85	785	10	1.3	29	3.7	784	10	1.3	29	3.7	12	6,195
WIN_T10	66.31	1,048	42	4.0	46	4.4	839	2	0.2	19	2.3	2,953	8,394
WIN_P	53.86	1,049	47	4.5	51	4.9	844	2	0.2	19	2.3	2,859	8,326
WIN_OP	42.11	935	47	5.0	50	5.3	728	2	0.3	19	2.6	3,337	8,723

Scenario: 1.1 Base Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	6,935	239	3.4	777	11.2	7,352	256	3.5	985	13.4	-535	5,042
SF_P	56.09	6,771	240	3.5	779	11.5	7,189	259	3.6	986	13.7	-544	5,021
SF_OP	42.17	5,588	241	4.3	805	14.4	6,007	267	4.4	1,037	17.3	-570	4,674
SUM_T1	86.41	8,461	621	7.3	830	9.8	8,804	635	7.2	985	11.2	-348	4,802
SUM_T10	74.71	8,161	621	7.6	829	10.2	8,504	635	7.5	983	11.6	-348	4,664
SUM_P	60.73	7,811	621	8.0	830	10.6	8,154	638	7.8	978	12.0	-348	4,504
SUM_OP	43.09	6,549	626	9.6	832	12.7	6,894	626	9.1	1,015	14.7	-355	4,158
WIN_T10	55.59	6,472	134	2.1	565	8.7	7,361	255	3.5	834	11.3	-1,367	5,087
WIN_P	52.58	6,326	164	2.6	570	9.0	7,213	259	3.6	888	12.3	-1,456	5,375
WIN_OP	42.17	5,785	142	2.4	568	9.8	6,676	260	3.9	899	13.5	-1,493	5,085

FPL/Vandolah

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	12,944	194	1.5	7,723	59.7	13,146	488	3.7	7,152	54.4	-586	3,401
SF_P	30.55	6,486	112	1.7	4,789	73.8	7,444	472	6.3	4,789	64.3	-1,256	4,305
SF_OP	28.33	3,706	112	3.0	1,466	39.6	4,647	468	10.1	1,466	31.5	-781	1,843
SUM_T1	56.09	14,049	114	0.8	8,862	63.1	13,682	203	1.5	8,271	60.4	-302	4,057
SUM_T10	49.74	13,611	114	0.8	8,424	61.9	13,244	204	1.5	7,833	59.1	-307	3,928
SUM_P	34.67	7,869	114	1.5	5,033	64.0	8,088	187	2.3	5,033	62.2	-230	4,179
SUM_OP	29.40	2,895	114	4.0	1,511	52.2	3,113	174	5.6	1,511	48.5	-407	2,827
WIN_T10	44.40	10,591	141	1.3	5,610	53.0	12,247	556	4.5	5,611	45.8	-770	2,641
WIN_P	31.21	4,786	141	2.9	2,868	59.9	6,245	549	8.8	2,868	45.9	-1,362	2,579
WIN_OP	31.24	5,474	135	2.5	2,502	45.7	6,566	549	8.4	2,502	38.1	-812	2,287

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	2,589	24	0.9	1	0.0	2,589	24	0.9	1	0.0	0	4,896
SF_P	43.61	2,577	24	0.9	1	0.0	2,577	24	0.9	1	0.0	0	4,920
SF_OP	29.75	1,534	24	1.6	0	0.0	1,534	24	1.6	0	0.0	0	4,318
SUM_T1	36.01	2,299	31	1.3	2	0.1	2,299	31	1.3	2	0.1	0	4,502
SUM_T10	66.19	3,464	31	0.9	2	0.0	3,464	31	0.9	2	0.0	0	4,706
SUM_P	46.99	3,118	31	1.0	1	0.0	3,118	31	1.0	1	0.0	0	4,806
SUM_OP	35.80	2,196	31	1.4	0	0.0	2,196	31	1.4	0	0.0	0	4,711
WIN_T10	38.56	2,558	28	1.1	0	0.0	2,558	28	1.1	0	0.0	0	4,673
WIN_P	47.53	2,928	28	0.9	0	0.0	2,928	28	0.9	0	0.0	0	4,992
WIN_OP	39.65	2,658	28	1.0	0	0.0	2,658	28	1.0	0	0.0	0	4,808

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	29,244	27,078	92.6	382	1.3	29,067	26,818	92.3	422	1.5	-60	8,526
SF_P	33.87	28,068	25,910	92.3	338	1.2	27,959	25,718	92.0	374	1.3	-60	8,475
SF_OP	30.71	24,812	22,886	92.2	0	0.0	24,736	22,810	92.2	0	0.0	-4	8,520
SUM_T1	54.18	35,300	33,750	95.6	0	0.0	35,877	34,043	94.9	0	0.0	-137	9,010
SUM_T10	43.27	32,615	31,303	96.0	0	0.0	32,615	31,303	96.0	0	0.0	0	9,217
SUM_P	39.92	28,219	27,096	96.0	0	0.0	28,219	27,096	96.0	0	0.0	0	9,228
SUM_OP	34.28	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	36.12	28,424	26,305	92.5	23	0.1	28,152	26,033	92.5	23	0.1	-13	8,565
WIN_P	35.05	28,789	26,667	92.6	114	0.4	28,597	26,475	92.6	114	0.4	-9	8,584
WIN_OP	33.76	26,252	24,124	91.9	21	0.1	26,172	24,044	91.9	21	0.1	-4	8,456

FPL/Vandolah

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	546	26	4.9	7	1.3	532	22	4.2	6	1.1	245	5,422
SF_P	73.62	363	28	7.6	8	2.1	349	23	6.7	6	1.9	241	3,860
SF_OP	51.78	267	30	11.1	8	3.0	254	25	9.9	7	2.7	202	2,814
SUM_T1	48.60	526	54	10.3	9	1.7	510	46	9.0	8	1.5	233	4,444
SUM_T10	38.41	306	55	18.0	4	1.3	290	47	16.2	3	1.1	158	2,655
SUM_P	65.82	530	37	7.0	10	1.8	513	32	6.2	8	1.6	239	4,477
SUM_OP	26.96	196	52	26.3	0	0.0	181	44	24.3	0	0.0	258	3,355
WIN_T10	69.19	268	21	7.7	4	1.7	256	17	6.6	4	1.4	242	3,357
WIN_P	61.24	269	23	8.7	5	1.7	257	19	7.4	4	1.5	239	3,355
WIN_OP	61.06	268	20	7.5	4	1.7	256	16	6.4	4	1.4	240	3,359

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	2,076	114	5.5	26	1.3	2,035	99	4.9	23	1.1	255	6,780
SF_P	33.80	848	110	12.9	6	0.7	806	94	11.6	5	0.6	325	4,331
SF_OP	27.34	334	97	29.0	0	0.0	293	84	28.5	0	0.0	-43	2,541
SUM_T1	56.75	2,878	176	6.1	36	1.3	2,869	174	6.1	36	1.2	36	6,389
SUM_T10	47.95	1,544	197	12.8	10	0.6	1,535	194	12.6	10	0.6	42	4,668
SUM_P	43.16	1,378	204	14.8	4	0.3	1,369	201	14.7	4	0.3	40	4,279
SUM_OP	32.97	1,046	153	14.6	0	0.0	1,037	150	14.5	0	0.0	30	3,280
WIN_T10	52.79	1,864	50	2.7	9	0.5	1,791	24	1.3	4	0.2	680	8,914
WIN_P	43.04	1,007	62	6.2	2	0.2	934	30	3.2	1	0.1	1,102	8,209
WIN_OP	42.17	842	50	6.0	10	1.2	768	24	3.2	5	0.6	1,263	7,894

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	2,354	0	0.0	0	0.0	2,354	0	0.0	0	0.0	0	9,388
SF_P	33.97	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	32.81	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	56.66	2,701	0	0.0	0	0.0	2,701	0	0.0	0	0.0	0	9,254
SUM_T10	57.70	2,977	0	0.0	0	0.0	2,977	0	0.0	0	0.0	0	9,322
SUM_P	47.81	2,496	0	0.0	0	0.0	2,496	0	0.0	0	0.0	0	9,455
SUM_OP	37.68	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	36.12	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	44.97	2,353	0	0.0	0	0.0	2,353	0	0.0	0	0.0	0	9,644
WIN_OP	36.43	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	45,893	654	1.4	1,771	3.9	45,890	652	1.4	1,771	3.9	0	3,951
SF_P	37.94	37,710	610	1.6	1,786	4.7	37,707	607	1.6	1,786	4.7	0	3,900
SF_OP	33.35	35,280	431	1.2	1,813	5.1	35,279	430	1.2	1,813	5.1	0	4,008
SUM_T1	67.33	53,909	901	1.7	1,038	1.9	53,909	911	1.7	1,037	1.9	0	4,343
SUM_T10	64.09	52,989	885	1.7	1,040	2.0	52,990	895	1.7	1,034	2.0	0	4,296
SUM_P	42.44	44,530	722	1.6	1,164	2.6	44,530	722	1.6	1,164	2.6	0	4,329
SUM_OP	39.60	40,743	577	1.4	1,095	2.7	40,743	577	1.4	1,095	2.7	0	4,354
WIN_T10	49.82	50,334	327	0.6	1,940	3.9	50,333	326	0.6	1,940	3.9	0	3,996
WIN_P	35.41	39,070	363	0.9	1,672	4.3	39,067	360	0.9	1,672	4.3	1	3,906
WIN_OP	33.50	35,584	225	0.6	1,573	4.4	35,584	224	0.6	1,573	4.4	0	4,028

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	882	38	4.3	42	4.7	777	16	2.0	27	3.5	1,450	6,697
SF_P	46.13	870	22	2.5	49	5.6	770	9	1.2	31	4.0	1,422	6,809
SF_OP	36.87	677	23	3.4	48	7.1	578	9	1.6	30	5.2	1,724	6,738
SUM_T1	75.23	916	10	1.1	34	3.7	915	10	1.1	33	3.7	10	6,028
SUM_T10	63.22	913	10	1.1	32	3.4	912	11	1.2	31	3.4	10	6,059
SUM_P	48.98	888	10	1.2	33	3.8	887	10	1.2	33	3.8	10	6,363
SUM_OP	36.69	459	10	2.2	30	6.6	458	10	2.2	30	6.6	12	4,455
WIN_T10	54.25	1,042	44	4.3	52	5.0	838	2	0.2	19	2.3	2,886	8,399
WIN_P	44.06	960	29	3.0	52	5.4	758	1	0.2	19	2.5	2,970	8,152
WIN_OP	34.45	571	25	4.4	50	8.7	378	1	0.3	19	5.1	4,083	7,667

Scenario: 1.2 Base Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	6,692	241	3.6	801	12.0	7,110	239	3.4	1,089	15.3	-552	5,324
SF_P	45.89	6,219	243	3.9	793	12.7	6,637	242	3.6	1,094	16.5	-545	5,085
SF_OP	34.51	5,585	241	4.3	759	13.6	6,003	240	4.0	998	16.6	-552	4,704
SUM_T1	70.69	8,392	622	7.4	820	9.8	8,735	636	7.3	966	11.1	-350	4,765
SUM_T10	61.13	8,156	623	7.6	835	10.2	8,499	639	7.5	988	11.6	-348	4,673
SUM_P	49.69	7,559	629	8.3	839	11.1	7,903	629	8.0	1,028	13.0	-366	4,716
SUM_OP	35.25	4,493	632	14.1	748	16.6	4,838	632	13.1	869	18.0	-338	3,093
WIN_T10	45.49	6,236	197	3.2	576	9.2	7,119	258	3.6	1,013	14.2	-1,414	5,383
WIN_P	43.02	6,113	219	3.6	557	9.1	6,994	260	3.7	921	13.2	-1,428	5,315
WIN_OP	34.51	3,454	211	6.1	557	16.1	4,334	261	6.0	899	20.7	-1,731	4,012

FPL/Vandolah

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	1,622	83	5.1	0	0.0	0	1,588
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	1,434	0	0.0	0	0.0	0	2,241
SUM_T10	55.27	1,432	0	0.0	0	0.0	1,432	0	0.0	0	0.0	0	2,247
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	372	17.0	0	0.0	0	1,274
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,943

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	48.45	560	317	56.7	0	0.0	560	317	56.7	0	0.0	0	3,978
SF_OP	33.06	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	40.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	73.55	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	52.21	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	39.78	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	42.84	206	19	9.1	0	0.0	206	19	9.1	0	0.0	0	6,747
WIN_P	52.81	923	358	38.7	0	0.0	923	358	38.7	0	0.0	0	2,820
WIN_OP	44.06	1,027	358	34.8	0	0.0	1,027	358	34.8	0	0.0	0	2,664

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,735	2,451	65.6	0	0.0	434	4,643
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,560	6,967	92.2	0	0.0	0	8,502
SF_OP	34.12	6,666	5,595	83.9	0	0.0	7,062	5,991	84.8	0	0.0	145	7,252
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	4,179	3,447	82.5	0	0.0	646	6,887
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,868	3,222	83.3	0	0.0	613	7,033
SUM_P	44.35	5,773	5,131	88.9	0	0.0	6,381	5,740	90.0	0	0.0	182	8,125
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,330	4,031	93.1	0	0.0	21	8,695
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	9,551	8,144	85.3	0	0.0	109	7,316
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,503	9,576	91.2	0	0.0	0	8,324
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	11,271	9,737	86.4	0	0.0	87	7,493

FPL/Vandolah

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	88	22	24.5	3	2.9	88	23	25.8	2	2.9	47	1,157
SF_P	81.80	187	28	15.1	8	4.5	187	29	15.5	8	4.4	9	3,156
SF_OP	57.53	91	29	32.2	8	8.7	91	30	33.1	8	8.6	45	1,636
SUM_T1	54.00	112	10	9.3	0	0.0	112	10	9.3	0	0.0	0	917
SUM_T10	42.68	112	16	14.1	0	0.0	112	16	14.1	0	0.0	0	1,350
SUM_P	35.24	112	18	16.6	0	0.0	112	18	16.6	0	0.0	0	1,453
SUM_OP	29.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	76.88	174	22	12.9	1	0.5	174	23	13.2	1	0.5	6	4,204
WIN_P	68.04	68	27	39.8	2	3.7	68	28	40.5	2	3.6	51	1,964
WIN_OP	67.84	75	22	28.7	3	4.6	75	22	29.3	3	4.5	23	1,637

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	411	102	24.8	0	0.0	411	109	26.5	0	0.0	67	1,154
SF_P	37.56	348	54	15.5	0	0.0	348	54	15.5	0	0.0	0	1,375
SF_OP	30.38	345	44	12.8	0	0.0	345	44	12.8	0	0.0	0	1,245
SUM_T1	63.06	603	99	16.4	0	0.0	604	124	20.6	0	0.0	108	880
SUM_T10	53.28	580	88	15.2	0	0.0	580	102	17.6	0	0.0	49	814
SUM_P	47.96	533	174	32.6	0	0.0	533	180	33.8	0	0.0	65	1,553
SUM_OP	36.63	530	22	4.2	0	0.0	530	28	5.3	0	0.0	-15	1,067
WIN_T10	58.66	224	61	27.1	0	0.0	224	62	27.7	0	0.0	29	1,560
WIN_P	45.19	165	101	61.3	0	0.0	165	101	61.3	0	0.0	0	3,944
WIN_OP	43.21	163	69	42.2	1	0.8	163	70	43.2	1	0.8	75	2,175

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	37.74	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	36.45	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	62.95	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	64.11	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	53.12	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	41.87	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	40.13	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	49.97	476	0	0.0	0	0.0	476	0	0.0	0	0.0	0	8,683
WIN_OP	40.48	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	12,706	797	6.3	2	0.0	12,706	797	6.3	2	0.0	0	579
SF_P	42.16	13,161	765	5.8	2	0.0	13,161	765	5.8	2	0.0	0	788
SF_OP	37.05	10,238	465	4.5	0	0.0	10,238	465	4.5	0	0.0	0	630
SUM_T1	74.81	13,118	1,045	8.0	66	0.5	13,118	1,054	8.0	66	0.5	1	644
SUM_T10	71.21	13,267	1,036	7.8	224	1.7	13,267	1,043	7.9	224	1.7	1	631
SUM_P	47.16	12,806	886	6.9	1	0.0	12,806	888	6.9	1	0.0	0	678
SUM_OP	44.00	13,175	712	5.4	1	0.0	13,175	713	5.4	1	0.0	0	962
WIN_T10	55.36	17,139	456	2.7	108	0.6	17,139	456	2.7	108	0.6	0	1,030
WIN_P	39.34	12,283	364	3.0	1	0.0	12,283	364	3.0	1	0.0	0	874
WIN_OP	37.22	10,509	222	2.1	0	0.0	10,509	222	2.1	0	0.0	0	704

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	279	20	7.2	18	6.5	279	20	7.2	18	6.5	0	818
SF_P	51.25	307	24	7.9	25	8.2	307	24	7.9	25	8.2	0	784
SF_OP	40.97	246	36	14.7	27	11.1	246	36	14.7	27	11.1	0	953
SUM_T1	83.59	234	11	4.7	18	7.6	234	12	5.0	18	7.6	0	849
SUM_T10	70.24	216	11	5.2	0	0.0	216	12	5.4	0	0.0	1	988
SUM_P	54.42	201	4	2.2	0	0.0	201	4	2.2	0	0.0	0	1,052
SUM_OP	40.77	179	2	1.0	0	0.0	179	2	1.0	0	0.0	0	1,396
WIN_T10	60.28	401	50	12.5	0	0.0	401	50	12.5	0	0.0	0	1,139
WIN_P	48.96	508	6	1.2	20	4.0	508	6	1.2	20	4.0	0	1,662
WIN_OP	38.28	306	3	1.1	0	0.0	306	3	1.1	0	0.0	0	942

Scenario: 2.0 But-for-Case
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	2,168	210	9.7	0	0.0	2,168	214	9.9	0	0.0	2	2,032
SF_P	50.99	2,803	272	9.7	186	6.6	2,803	273	9.7	186	6.6	0	3,326
SF_OP	38.34	2,375	282	11.9	0	0.0	2,375	282	11.9	0	0.0	0	3,097
SUM_T1	78.55	2,817	518	18.4	0	0.0	2,817	544	19.3	0	0.0	27	1,668
SUM_T10	67.92	2,807	549	19.5	0	0.0	2,807	568	20.2	0	0.0	23	1,684
SUM_P	55.21	3,236	600	18.5	0	0.0	3,236	606	18.7	0	0.0	6	2,617
SUM_OP	39.17	2,677	608	22.7	0	0.0	2,677	609	22.7	0	0.0	1	2,091
WIN_T10	50.54	2,338	241	10.3	0	0.0	2,338	241	10.3	0	0.0	0	5,705
WIN_P	47.80	3,099	271	8.7	5	0.2	3,099	271	8.7	5	0.2	0	6,609
WIN_OP	38.34	2,866	258	9.0	0	0.0	2,866	258	9.0	0	0.0	0	6,370

FPL/Vandolah

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	1,874	103	5.5	250	13.3	1	1,394
SF_P	37.33	1,730	86	5.0	636	36.8	1,730	86	5.0	636	36.8	0	2,351
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,382	256	10.7	928	39.0	-188	2,367
SUM_T1	68.55	1,434	0	0.0	0	0.0	1,434	0	0.0	0	0.0	0	2,241
SUM_T10	60.80	1,434	0	0.0	0	0.0	1,434	0	0.0	0	0.0	0	2,241
SUM_P	42.37	1,032	0	0.0	0	0.0	1,032	0	0.0	0	0.0	0	3,256
SUM_OP	35.94	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	54.26	2,327	363	15.6	0	0.0	2,327	372	16.0	0	0.0	9	1,229
WIN_P	38.15	1,633	248	15.2	180	11.0	1,633	248	15.2	180	11.0	0	1,781
WIN_OP	38.18	2,796	573	20.5	370	13.2	2,796	573	20.5	370	13.2	0	1,717

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	53.30	639	317	49.7	0	0.0	639	317	49.7	0	0.0	0	3,259
SF_OP	36.37	480	317	66.1	0	0.0	480	317	66.1	0	0.0	0	5,280
SUM_T1	44.01	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_T10	80.91	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	57.43	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	43.76	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	47.12	206	19	9.1	0	0.0	206	19	9.1	0	0.0	0	6,747
WIN_P	58.09	1,016	358	35.2	0	0.0	1,016	358	35.2	0	0.0	0	2,623
WIN_OP	48.47	1,164	358	30.7	0	0.0	1,164	358	30.7	0	0.0	0	2,821

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,948	3,332	67.3	0	0.0	324	4,814
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,850	8,468	86.0	0	0.0	95	7,455
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,878	6,563	83.3	0	0.0	141	6,992
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	4,179	3,447	82.5	0	0.0	646	6,887
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,868	3,222	83.3	0	0.0	613	7,033
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,751	6,109	90.5	0	0.0	163	8,221
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,589	6,117	92.8	0	0.0	105	8,636
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	10,002	8,430	84.3	0	0.0	109	7,150
WIN_P	42.83	12,693	11,138	87.8	0	0.0	13,105	11,551	88.1	0	0.0	66	7,793
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,699	11,160	87.9	91	0.7	70	7,741

FPL/Vandolah

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	88	19	21.9	3	3.1	88	20	23.1	3	3.1	29	1,310
SF_P	89.98	187	27	14.4	8	4.2	187	28	14.8	8	4.2	8	3,162
SF_OP	63.28	91	26	29.0	9	9.6	91	27	29.9	9	9.5	34	1,538
SUM_T1	59.40	113	23	20.2	0	0.0	113	30	26.2	0	0.0	201	1,125
SUM_T10	46.95	112	15	13.5	0	0.0	113	22	19.7	0	0.0	74	1,206
SUM_P	38.76	112	18	16.2	0	0.0	112	18	16.2	0	0.0	0	1,401
SUM_OP	32.96	111	15	13.2	0	0.0	111	15	13.2	0	0.0	0	1,130
WIN_T10	84.57	174	20	11.5	1	0.6	174	20	11.8	1	0.6	4	4,210
WIN_P	74.84	177	24	13.5	3	1.9	177	24	13.8	3	1.9	5	4,291
WIN_OP	74.62	184	20	11.0	3	1.8	184	21	11.2	3	1.8	3	4,462

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	411	98	23.9	0	0.0	411	104	25.3	0	0.0	57	1,079
SF_P	41.32	349	226	64.6	0	0.0	349	226	64.6	0	0.0	0	4,302
SF_OP	33.42	346	137	39.6	0	0.0	346	137	39.6	0	0.0	0	2,030
SUM_T1	69.37	604	112	18.6	0	0.0	604	134	22.2	0	0.0	110	916
SUM_T10	58.61	604	143	23.7	0	0.0	604	164	27.2	0	0.0	145	1,116
SUM_P	52.76	578	189	32.6	0	0.0	578	193	33.4	0	0.0	45	1,468
SUM_OP	40.29	531	221	41.6	0	0.0	531	223	42.0	0	0.0	29	2,118
WIN_T10	64.53	224	58	25.7	0	0.0	224	59	26.3	0	0.0	24	1,531
WIN_P	49.71	165	74	45.1	0	0.0	165	74	45.1	0	0.0	0	2,321
WIN_OP	47.53	163	61	37.5	2	1.3	163	62	38.3	2	1.3	50	1,909

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	41.51	145	0	0.0	0	0.0	145	0	0.0	0	0.0	0	4,941
SF_OP	40.10	269	0	0.0	0	0.0	269	0	0.0	0	0.0	0	8,400
SUM_T1	69.25	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	70.52	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	58.43	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	46.06	250	0	0.0	0	0.0	250	0	0.0	0	0.0	0	8,150
WIN_T10	44.14	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	54.97	619	0	0.0	0	0.0	619	0	0.0	0	0.0	0	8,973
WIN_OP	44.53	877	0	0.0	0	0.0	877	0	0.0	0	0.0	0	9,668

FPL/Vandolah

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	13,442	793	5.9	2	0.0	13,442	796	5.9	2	0.0	0	586
SF_P	46.38	15,847	790	5.0	4	0.0	15,847	790	5.0	4	0.0	0	1,120
SF_OP	40.76	13,455	612	4.5	78	0.6	13,455	613	4.6	78	0.6	0	885
SUM_T1	82.29	13,320	1,045	7.8	68	0.5	13,320	1,054	7.9	68	0.5	1	632
SUM_T10	78.33	13,725	1,036	7.5	231	1.7	13,725	1,043	7.6	231	1.7	1	611
SUM_P	51.88	14,516	889	6.1	1	0.0	14,516	891	6.1	1	0.0	0	963
SUM_OP	48.40	14,446	709	4.9	83	0.6	14,446	711	4.9	83	0.6	0	1,265
WIN_T10	60.90	19,897	456	2.3	112	0.6	19,897	456	2.3	112	0.6	0	1,231
WIN_P	43.27	16,598	547	3.3	1	0.0	16,598	547	3.3	1	0.0	0	1,239
WIN_OP	40.94	15,177	412	2.7	171	1.1	15,177	412	2.7	171	1.1	0	1,027

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	279	22	7.8	21	7.5	279	24	8.4	21	7.5	2	823
SF_P	56.38	307	35	11.5	26	8.6	307	35	11.5	26	8.6	0	765
SF_OP	45.07	322	36	11.1	27	8.3	322	36	11.1	27	8.3	0	1,063
SUM_T1	91.95	234	11	4.7	18	7.6	234	12	4.9	18	7.6	0	834
SUM_T10	77.26	234	12	4.9	18	7.6	234	12	5.0	18	7.6	1	865
SUM_P	59.86	219	12	5.5	18	8.4	219	12	5.5	18	8.4	0	743
SUM_OP	44.85	197	10	5.1	18	9.1	197	10	5.1	18	9.1	0	924
WIN_T10	66.31	401	51	12.6	0	0.0	401	51	12.6	0	0.0	0	1,128
WIN_P	53.86	508	46	9.1	19	3.7	508	46	9.1	19	3.7	0	1,693
WIN_OP	42.11	428	52	12.0	22	5.1	428	52	12.0	22	5.1	0	1,467

Scenario: 2.1 But-for-Case, Price +10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	2,174	214	9.8	0	0.0	2,174	217	10.0	0	0.0	2	2,006
SF_P	56.09	3,177	262	8.3	256	8.1	3,177	263	8.3	256	8.1	0	3,752
SF_OP	42.17	2,375	265	11.2	289	12.2	2,375	266	11.2	289	12.2	1	3,092
SUM_T1	86.41	2,817	515	18.3	0	0.0	2,817	542	19.2	0	0.0	27	1,663
SUM_T10	74.71	2,807	550	19.6	4	0.1	2,807	568	20.2	4	0.1	22	1,683
SUM_P	60.73	3,446	585	17.0	148	4.3	3,446	591	17.2	148	4.3	5	2,446
SUM_OP	43.09	2,677	602	22.5	0	0.0	2,677	603	22.5	0	0.0	1	2,079
WIN_T10	55.59	2,572	184	7.2	0	0.0	2,572	189	7.3	0	0.0	2	5,096
WIN_P	52.58	3,099	265	8.6	5	0.2	3,099	265	8.6	5	0.2	0	6,606
WIN_OP	42.17	2,866	250	8.7	10	0.3	2,866	253	8.8	10	0.3	2	6,367

FPL/Vandolah

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	1,621	44	2.7	0	0.0	0	1,566
SF_P	30.55	1,046	53	5.1	0	0.0	1,046	53	5.1	0	0.0	0	2,512
SF_OP	28.33	817	44	5.3	0	0.0	817	44	5.3	0	0.0	0	3,510
SUM_T1	56.09	1,432	0	0.0	0	0.0	1,432	0	0.0	0	0.0	0	2,247
SUM_T10	49.74	1,432	0	0.0	0	0.0	1,432	0	0.0	0	0.0	0	2,247
SUM_P	34.67	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	29.40	557	0	0.0	0	0.0	557	0	0.0	0	0.0	0	8,611
WIN_T10	44.40	2,190	398	18.2	0	0.0	2,190	398	18.2	0	0.0	0	1,320
WIN_P	31.21	1,096	72	6.5	0	0.0	1,096	72	6.5	0	0.0	0	2,273
WIN_OP	31.24	1,006	46	4.6	0	0.0	1,006	46	4.6	0	0.0	0	2,513

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	43.61	519	317	61.1	0	0.0	519	317	61.1	0	0.0	0	4,563
SF_OP	29.75	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	36.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	66.19	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	46.99	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	35.80	196	0	0.0	0	0.0	196	0	0.0	0	0.0	0	8,289
WIN_T10	38.56	206	19	9.1	0	0.0	206	19	9.1	0	0.0	0	6,747
WIN_P	47.53	820	358	43.6	0	0.0	820	358	43.6	0	0.0	0	2,894
WIN_OP	39.65	823	358	43.5	0	0.0	823	358	43.5	0	0.0	0	2,948

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	1,155	530	45.9	0	0.0	0	2,565
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,383	5,823	91.2	0	0.0	0	8,337
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,312	5,807	92.0	0	0.0	0	8,479
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	4,046	3,327	82.2	0	0.0	676	6,850
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	2,123	1,641	77.3	0	0.0	562	6,147
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,382	3,078	91.0	0	0.0	88	8,331
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,330	4,031	93.1	0	0.0	21	8,695
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,053	5,291	87.4	0	0.0	0	7,677
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,358	9,580	92.5	0	0.0	0	8,563
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	10,064	9,348	92.9	0	0.0	0	8,636

FPL/Vandolah

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	88	22	25.0	3	3.0	88	23	26.3	3	2.9	50	1,145
SF_P	73.62	187	29	15.8	8	4.5	187	30	16.2	8	4.5	10	3,161
SF_OP	51.78	92	35	38.7	10	10.4	92	36	39.8	9	10.2	73	1,881
SUM_T1	48.60	112	13	11.8	0	0.0	112	13	11.8	0	0.0	0	1,017
SUM_T10	38.41	112	18	16.4	0	0.0	112	18	16.4	0	0.0	0	1,591
SUM_P	31.72	112	19	16.8	0	0.0	112	19	16.8	0	0.0	0	1,486
SUM_OP	26.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	69.19	65	25	38.9	0	0.0	65	26	39.9	0	0.0	63	2,021
WIN_P	61.24	68	33	48.2	2	2.4	68	34	49.0	2	2.3	72	2,598
WIN_OP	61.06	75	24	31.5	3	3.5	75	24	32.2	3	3.4	30	1,708

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	411	104	25.4	0	0.0	411	112	27.2	0	0.0	77	1,179
SF_P	33.80	347	55	15.8	0	0.0	347	55	15.8	0	0.0	0	1,431
SF_OP	27.34	345	46	13.2	0	0.0	345	46	13.2	0	0.0	0	1,331
SUM_T1	56.75	603	104	17.3	0	0.0	604	133	22.0	0	0.0	135	911
SUM_T10	47.95	535	50	9.3	0	0.0	535	71	13.3	0	0.0	16	930
SUM_P	43.16	533	151	28.3	0	0.0	533	161	30.2	0	0.0	83	1,416
SUM_OP	32.97	529	43	8.2	0	0.0	529	43	8.2	0	0.0	0	960
WIN_T10	52.79	176	72	40.8	0	0.0	176	72	40.8	0	0.0	0	1,998
WIN_P	40.67	165	104	62.6	0	0.0	165	104	62.6	0	0.0	0	4,135
WIN_OP	38.89	163	91	55.6	0	0.0	163	91	55.6	0	0.0	0	3,297

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	33.97	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	32.81	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	56.66	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	57.70	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	47.81	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	37.68	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	36.12	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	44.97	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	8,207
WIN_OP	36.43	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	11,947	796	6.7	2	0.0	11,947	796	6.7	2	0.0	0	571
SF_P	37.94	9,664	617	6.4	2	0.0	9,664	617	6.4	2	0.0	0	675
SF_OP	33.35	9,572	428	4.5	0	0.0	9,572	428	4.5	0	0.0	0	792
SUM_T1	67.33	12,836	1,052	8.2	1	0.0	12,836	1,062	8.3	1	0.0	1	660
SUM_T10	64.09	12,802	1,047	8.2	1	0.0	12,802	1,054	8.2	1	0.0	1	661
SUM_P	42.44	10,604	840	7.9	1	0.0	10,604	853	8.0	1	0.0	2	562
SUM_OP	39.60	10,529	718	6.8	0	0.0	10,529	718	6.8	0	0.0	0	620
WIN_T10	49.82	14,197	459	3.2	0	0.0	14,197	459	3.2	0	0.0	0	780
WIN_P	35.41	9,384	283	3.0	1	0.0	9,384	283	3.0	1	0.0	0	808
WIN_OP	33.50	8,067	218	2.7	0	0.0	8,067	218	2.7	0	0.0	0	861

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	261	15	5.6	0	0.0	261	15	5.6	0	0.0	0	909
SF_P	46.13	289	12	4.2	0	0.1	289	12	4.2	0	0.1	0	797
SF_OP	36.87	228	4	1.6	0	0.0	228	4	1.6	0	0.0	0	867
SUM_T1	75.23	216	11	5.1	0	0.0	216	12	5.4	0	0.0	1	934
SUM_T10	63.22	216	6	2.9	0	0.1	216	8	3.6	0	0.1	-5	912
SUM_P	48.98	202	5	2.6	0	0.1	202	5	2.6	0	0.1	0	852
SUM_OP	36.69	180	3	1.8	0	0.1	180	3	1.8	0	0.1	0	983
WIN_T10	54.25	401	40	9.9	0	0.0	401	40	9.9	0	0.0	0	1,303
WIN_P	44.06	403	9	2.2	0	0.1	403	9	2.2	0	0.1	0	1,417
WIN_OP	34.45	279	5	1.8	0	0.1	279	5	1.8	0	0.1	0	1,980

Scenario: 2.2 But-for-Case, Price -10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	1,931	213	11.0	0	0.0	1,931	219	11.3	0	0.0	3	2,241
SF_P	45.89	2,626	282	10.7	0	0.0	2,626	282	10.7	0	0.0	0	3,549
SF_OP	34.51	2,376	246	10.3	0	0.0	2,376	246	10.3	0	0.0	0	3,166
SUM_T1	70.69	2,747	514	18.7	0	0.0	2,747	543	19.8	0	0.0	30	1,591
SUM_T10	61.13	2,800	543	19.4	0	0.0	2,800	559	20.0	0	0.0	17	1,695
SUM_P	49.69	3,197	614	19.2	0	0.0	3,197	618	19.3	0	0.0	4	2,697
SUM_OP	35.25	1,044	50	4.8	0	0.0	1,044	50	4.8	0	0.0	0	2,608
WIN_T10	45.49	2,338	228	9.8	0	0.0	2,338	228	9.8	0	0.0	0	5,697
WIN_P	43.02	2,888	261	9.0	0	0.0	2,888	261	9.0	0	0.0	0	6,396
WIN_OP	34.51	540	263	48.7	0	0.0	540	263	48.7	0	0.0	0	3,339

FPL/Vandolah

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	13,297	195	1.5	8,077	60.7	12,522	112	0.9	7,505	59.9	-48	4,047
SF_P	33.94	8,913	112	1.3	5,538	62.1	8,913	112	1.3	5,538	62.1	0	4,175
SF_OP	31.48	7,121	112	1.6	4,300	60.4	7,121	112	1.6	4,300	60.4	0	3,986
SUM_T1	62.32	14,675	114	0.8	9,486	64.6	14,084	114	0.8	8,895	63.2	-160	4,367
SUM_T10	55.27	14,084	114	0.8	8,897	63.2	13,493	114	0.8	8,306	61.6	-168	4,201
SUM_P	38.52	11,044	114	1.0	6,922	62.7	11,044	114	1.0	6,922	62.7	0	4,298
SUM_OP	32.67	6,335	114	1.8	3,586	56.6	6,335	114	1.8	3,586	56.6	0	3,671
WIN_T10	49.33	10,978	139	1.3	5,964	54.3	10,978	139	1.3	5,964	54.3	0	3,528
WIN_P	34.68	8,203	139	1.7	4,891	59.6	8,203	139	1.7	4,891	59.6	0	4,041
WIN_OP	34.71	9,198	146	1.6	5,050	54.9	9,198	146	1.6	5,050	54.9	0	3,564

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	48.45	2,666	24	0.9	1	0.0	2,666	24	0.9	1	0.0	0	5,022
SF_OP	33.06	1,812	24	1.3	0	0.0	1,812	24	1.3	0	0.0	0	4,817
SUM_T1	40.01	2,411	31	1.3	2	0.1	2,411	31	1.3	2	0.1	0	4,650
SUM_T10	73.55	3,492	31	0.9	2	0.0	3,492	31	0.9	2	0.0	0	4,728
SUM_P	52.21	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	39.78	2,424	31	1.3	0	0.0	2,424	31	1.3	0	0.0	0	4,992
WIN_T10	42.84	2,904	28	1.0	0	0.0	2,904	28	1.0	0	0.0	0	5,038
WIN_P	52.81	3,032	28	0.9	0	0.0	3,032	28	0.9	0	0.0	0	5,097
WIN_OP	44.06	2,861	28	1.0	0	0.0	2,861	28	1.0	0	0.0	0	5,022

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	30,951	28,608	92.4	494	1.6	31,347	29,004	92.5	494	1.6	17	8,572
SF_P	37.63	29,246	27,059	92.5	306	1.0	29,246	27,059	92.5	306	1.0	0	8,573
SF_OP	34.12	25,065	22,913	91.4	490	2.0	25,461	23,309	91.5	490	1.9	24	8,397
SUM_T1	60.20	35,433	33,870	95.6	0	0.0	36,258	34,695	95.7	0	0.0	19	9,162
SUM_T10	48.08	33,932	32,455	95.6	0	0.0	34,692	33,215	95.7	0	0.0	18	9,173
SUM_P	44.35	30,793	29,333	95.3	0	0.0	31,402	29,942	95.4	0	0.0	17	9,099
SUM_OP	38.09	25,536	24,431	95.7	0	0.0	25,608	24,503	95.7	0	0.0	2	9,165
WIN_T10	40.13	30,943	28,595	92.4	247	0.8	31,355	29,008	92.5	247	0.8	18	8,569
WIN_P	38.94	28,801	26,664	92.6	132	0.5	28,801	26,664	92.6	132	0.5	0	8,584
WIN_OP	37.51	26,267	24,124	91.8	345	1.3	26,679	24,536	92.0	345	1.3	23	8,473

FPL/Vandolah

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	545	26	4.8	7	1.4	545	26	4.9	7	1.4	-6	5,180
SF_P	81.80	362	27	7.4	8	2.2	362	27	7.5	8	2.2	-6	3,621
SF_OP	57.53	266	27	10.2	8	3.0	267	28	10.3	8	3.0	-5	2,610
SUM_T1	54.00	526	44	8.4	11	2.0	526	45	8.5	11	2.0	-7	4,213
SUM_T10	42.68	307	56	18.3	5	1.8	308	57	18.5	5	1.8	-3	2,492
SUM_P	35.24	301	63	20.9	3	1.1	302	64	21.2	3	1.1	-5	2,625
SUM_OP	29.96	199	30	14.9	0	0.0	199	30	15.0	0	0.0	-5	2,984
WIN_T10	76.88	377	20	5.3	5	1.2	377	20	5.3	5	1.2	-5	4,227
WIN_P	68.04	268	22	8.0	5	1.7	268	22	8.1	5	1.7	-5	3,116
WIN_OP	67.84	268	19	7.2	5	1.7	268	20	7.3	5	1.7	-5	3,118

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	2,556	108	4.2	24	1.0	2,557	109	4.3	24	1.0	-7	7,122
SF_P	37.56	1,007	165	16.4	4	0.4	1,007	165	16.4	4	0.4	0	4,738
SF_OP	30.38	840	103	12.2	0	0.0	840	103	12.2	0	0.0	0	4,052
SUM_T1	63.06	2,872	167	5.8	37	1.3	2,876	171	5.9	37	1.3	-16	6,356
SUM_T10	53.28	2,167	177	8.2	29	1.3	2,169	179	8.3	29	1.3	-8	5,541
SUM_P	47.96	1,856	188	10.1	18	0.9	1,857	189	10.2	18	0.9	-6	5,333
SUM_OP	36.63	1,051	183	17.4	0	0.0	1,052	184	17.5	0	0.0	-2	3,252
WIN_T10	58.66	1,910	47	2.5	8	0.4	1,911	48	2.5	8	0.4	-5	7,846
WIN_P	45.19	1,168	60	5.2	2	0.1	1,168	60	5.2	2	0.1	0	7,468
WIN_OP	43.21	1,002	49	4.9	10	1.0	1,002	50	5.0	10	1.0	-11	7,114

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	2,626	0	0.0	0	0.0	2,626	0	0.0	0	0.0	0	9,451
SF_P	37.74	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	36.45	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	62.95	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	64.11	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	53.12	2,619	0	0.0	0	0.0	2,619	0	0.0	0	0.0	0	9,480
SUM_OP	41.87	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	40.13	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	49.97	2,487	0	0.0	0	0.0	2,487	0	0.0	0	0.0	0	9,663
WIN_OP	40.48	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	47,743	650	1.4	1,761	3.7	47,743	650	1.4	1,761	3.7	0	4,014
SF_P	42.16	42,004	600	1.4	1,737	4.1	42,004	600	1.4	1,737	4.1	0	3,871
SF_OP	37.05	35,446	427	1.2	1,789	5.0	35,446	427	1.2	1,789	5.0	0	4,007
SUM_T1	74.81	55,382	892	1.6	1,092	2.0	55,390	901	1.6	1,092	2.0	-1	4,393
SUM_T10	71.21	55,082	876	1.6	1,094	2.0	55,090	884	1.6	1,094	2.0	-1	4,414
SUM_P	47.16	46,881	722	1.5	1,027	2.2	46,884	724	1.5	1,027	2.2	0	4,362
SUM_OP	44.00	43,582	576	1.3	958	2.2	43,583	577	1.3	958	2.2	0	4,365
WIN_T10	55.36	52,964	323	0.6	1,944	3.7	52,966	324	0.6	1,944	3.7	0	4,074
WIN_P	39.34	41,976	358	0.9	1,678	4.0	41,976	358	0.9	1,678	4.0	0	4,055
WIN_OP	37.22	38,072	220	0.6	1,884	4.9	38,072	220	0.6	1,884	4.9	0	4,014

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	882	36	4.1	41	4.7	882	36	4.1	41	4.7	0	5,242
SF_P	51.25	873	42	4.8	45	5.2	873	42	4.8	45	5.2	0	5,349
SF_OP	40.97	760	40	5.3	43	5.6	760	40	5.3	43	5.6	0	5,295
SUM_T1	83.59	916	10	1.1	34	3.7	916	10	1.1	34	3.7	-3	6,012
SUM_T10	70.24	916	10	1.1	34	3.7	916	10	1.1	34	3.7	-3	6,018
SUM_P	54.42	896	10	1.1	30	3.4	896	10	1.2	30	3.4	-1	6,231
SUM_OP	40.77	699	10	1.4	31	4.4	699	10	1.4	31	4.4	-1	5,853
WIN_T10	60.28	1,048	43	4.1	46	4.4	1,048	43	4.1	46	4.4	0	5,444
WIN_P	48.96	1,036	23	2.3	51	4.9	1,036	23	2.3	51	4.9	0	5,606
WIN_OP	38.28	815	23	2.8	46	5.6	815	23	2.8	46	5.6	0	5,111

Scenario: 1.0 But-for-Case
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	6,924	234	3.4	781	11.3	6,927	238	3.4	781	11.3	-5	5,592
SF_P	50.99	6,392	236	3.7	792	12.4	6,395	240	3.7	792	12.4	-5	5,447
SF_OP	38.34	5,586	241	4.3	784	14.0	5,586	241	4.3	784	14.0	0	5,242
SUM_T1	78.55	8,446	607	7.2	829	9.8	8,461	622	7.3	829	9.8	-15	5,150
SUM_T10	67.92	8,149	608	7.5	824	10.1	8,163	622	7.6	824	10.1	-15	5,009
SUM_P	55.21	7,589	612	8.1	840	11.1	7,602	625	8.2	840	11.1	-14	5,023
SUM_OP	39.17	6,544	625	9.5	815	12.5	6,546	627	9.6	815	12.5	-2	4,513
WIN_T10	50.54	6,236	160	2.6	568	9.1	6,236	160	2.6	568	9.1	0	6,794
WIN_P	47.80	6,324	200	3.2	578	9.1	6,324	200	3.2	578	9.1	0	6,840
WIN_OP	38.34	5,784	174	3.0	566	9.8	5,784	174	3.0	566	9.8	0	6,582

FPL/Vandolah

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	13,857	190	1.4	8,635	62.3	13,083	112	0.9	8,064	61.6	-42	4,215
SF_P	37.33	10,902	112	1.0	6,592	60.5	10,902	112	1.0	6,592	60.5	0	4,094
SF_OP	34.63	10,716	112	1.0	6,246	58.3	10,573	112	1.1	6,103	57.7	-51	3,888
SUM_T1	68.55	14,810	114	0.8	9,622	65.0	14,219	114	0.8	9,030	63.5	-158	4,404
SUM_T10	60.80	14,558	114	0.8	9,369	64.4	13,966	114	0.8	8,778	62.8	-161	4,334
SUM_P	42.37	11,327	114	1.0	6,922	61.1	11,327	114	1.0	6,922	61.1	0	4,153
SUM_OP	35.94	9,461	114	1.2	5,191	54.9	9,461	114	1.2	5,191	54.9	0	3,593
WIN_T10	54.26	11,350	140	1.2	6,345	55.9	11,350	140	1.2	6,345	55.9	0	3,662
WIN_P	38.15	9,444	141	1.5	5,416	57.4	9,444	141	1.5	5,416	57.4	0	3,760
WIN_OP	38.18	9,720	143	1.5	5,050	52.0	9,720	143	1.5	5,050	52.0	0	3,421

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	53.30	2,745	24	0.9	1	0.0	2,745	24	0.9	1	0.0	0	4,939
SF_OP	36.37	2,015	24	1.2	0	0.0	2,015	24	1.2	0	0.0	0	5,124
SUM_T1	44.01	2,416	31	1.3	2	0.1	2,416	31	1.3	2	0.1	0	4,631
SUM_T10	80.91	3,507	31	0.9	2	0.0	3,507	31	0.9	2	0.0	0	4,740
SUM_P	57.43	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	43.76	2,623	31	1.2	0	0.0	2,623	31	1.2	0	0.0	0	5,244
WIN_T10	47.12	3,008	28	0.9	0	0.0	3,008	28	0.9	0	0.0	0	5,143
WIN_P	58.09	3,124	28	0.9	0	0.0	3,124	28	0.9	0	0.0	0	5,005
WIN_OP	48.47	2,998	28	0.9	0	0.0	2,998	28	0.9	0	0.0	0	5,161

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	31,999	29,493	92.2	626	2.0	32,395	29,889	92.3	626	1.9	17	8,525
SF_P	41.39	30,664	28,166	91.9	483	1.6	31,060	28,562	92.0	483	1.6	19	8,468
SF_OP	37.53	25,672	23,490	91.5	590	2.3	26,067	23,886	91.6	590	2.3	23	8,412
SUM_T1	66.22	35,433	33,870	95.6	0	0.0	36,258	34,695	95.7	0	0.0	19	9,162
SUM_T10	52.89	33,932	32,455	95.6	0	0.0	34,692	33,215	95.7	0	0.0	18	9,173
SUM_P	48.79	31,163	29,703	95.3	0	0.0	31,771	30,311	95.4	0	0.0	17	9,109
SUM_OP	41.90	27,370	26,092	95.3	0	0.0	27,867	26,589	95.4	0	0.0	16	9,112
WIN_T10	44.14	31,315	28,806	92.0	348	1.1	31,727	29,218	92.1	348	1.1	19	8,492
WIN_P	42.83	30,575	28,240	92.4	300	1.0	30,988	28,652	92.5	300	1.0	18	8,560
WIN_OP	41.26	28,028	25,727	91.8	270	1.0	28,440	26,139	91.9	270	1.0	21	8,460

FPL/Vandolah

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	545	26	4.7	7	1.3	545	26	4.7	7	1.3	-6	5,180
SF_P	89.98	362	26	7.3	8	2.2	362	27	7.4	8	2.2	-6	3,622
SF_OP	63.28	266	26	9.8	8	3.1	267	26	9.9	8	3.1	-5	2,601
SUM_T1	59.40	529	40	7.6	9	1.7	530	41	7.7	9	1.7	-13	4,229
SUM_T10	46.95	526	56	10.6	8	1.6	526	56	10.7	8	1.6	-7	4,212
SUM_P	38.76	304	67	22.0	2	0.7	305	68	22.2	2	0.7	-2	2,633
SUM_OP	32.96	200	42	21.1	0	0.0	200	42	21.2	0	0.0	-3	3,005
WIN_T10	84.57	377	19	5.1	4	1.2	377	20	5.2	4	1.2	-5	4,228
WIN_P	74.84	377	20	5.4	5	1.3	378	21	5.5	5	1.3	-5	4,222
WIN_OP	74.62	377	19	5.0	5	1.2	377	19	5.0	5	1.2	-6	4,229

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	2,556	104	4.1	26	1.0	2,558	105	4.1	26	1.0	-7	7,119
SF_P	41.32	1,167	149	12.8	6	0.5	1,167	149	12.8	6	0.5	0	5,246
SF_OP	33.42	847	142	16.8	0	0.0	847	142	16.8	0	0.0	0	4,061
SUM_T1	69.37	2,873	162	5.6	41	1.4	2,876	166	5.8	41	1.4	-16	6,354
SUM_T10	58.61	2,874	172	6.0	39	1.4	2,878	176	6.1	39	1.4	-16	6,352
SUM_P	52.76	2,162	176	8.2	34	1.6	2,163	178	8.2	34	1.6	-5	5,547
SUM_OP	40.29	1,212	185	15.3	16	1.3	1,213	186	15.3	16	1.3	-2	3,708
WIN_T10	64.53	1,910	46	2.4	8	0.4	1,911	47	2.5	8	0.4	-5	7,845
WIN_P	49.71	1,488	54	3.6	5	0.3	1,488	54	3.6	5	0.3	0	7,964
WIN_OP	47.53	1,483	48	3.2	9	0.6	1,484	49	3.3	9	0.6	-8	7,980

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	2,762	0	0.0	0	0.0	2,762	0	0.0	0	0.0	0	9,477
SF_P	41.51	2,211	0	0.0	0	0.0	2,211	0	0.0	0	0.0	0	9,440
SF_OP	40.10	2,175	0	0.0	0	0.0	2,175	0	0.0	0	0.0	0	9,730
SUM_T1	69.25	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	70.52	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	58.43	2,895	0	0.0	0	0.0	2,895	0	0.0	0	0.0	0	9,529
SUM_OP	46.06	2,685	0	0.0	0	0.0	2,685	0	0.0	0	0.0	0	9,755
WIN_T10	44.14	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	54.97	2,630	0	0.0	0	0.0	2,630	0	0.0	0	0.0	0	9,681
WIN_OP	44.53	2,729	0	0.0	0	0.0	2,729	0	0.0	0	0.0	0	9,862

FPL/Vandolah

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	48,197	645	1.3	1,821	3.8	48,200	648	1.3	1,821	3.8	-1	3,966
SF_P	46.38	44,224	600	1.4	1,706	3.9	44,224	600	1.4	1,706	3.9	0	4,001
SF_OP	40.76	39,191	440	1.1	1,710	4.4	39,196	445	1.1	1,710	4.4	-1	3,837
SUM_T1	82.29	55,613	892	1.6	1,077	1.9	55,621	901	1.6	1,077	1.9	-1	4,364
SUM_T10	78.33	55,540	876	1.6	1,085	2.0	55,548	884	1.6	1,085	2.0	-1	4,375
SUM_P	51.88	48,598	721	1.5	968	2.0	48,601	723	1.5	968	2.0	0	4,446
SUM_OP	48.40	45,312	567	1.3	949	2.1	45,319	574	1.3	949	2.1	-1	4,501
WIN_T10	60.90	54,690	323	0.6	1,852	3.4	54,691	324	0.6	1,852	3.4	0	4,220
WIN_P	43.27	46,753	353	0.8	1,866	4.0	46,753	353	0.8	1,866	4.0	0	3,928
WIN_OP	40.94	42,451	312	0.7	1,899	4.5	42,453	314	0.7	1,899	4.5	0	3,919

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	884	35	4.0	43	4.9	884	36	4.0	43	4.8	-5	5,222
SF_P	56.38	880	39	4.4	41	4.7	880	39	4.4	41	4.7	0	5,261
SF_OP	45.07	846	38	4.5	40	4.8	846	38	4.5	40	4.8	0	5,614
SUM_T1	91.95	916	10	1.1	33	3.6	916	10	1.1	33	3.6	-3	6,010
SUM_T10	77.26	916	10	1.1	34	3.7	916	10	1.1	34	3.7	-3	6,017
SUM_P	59.86	896	10	1.1	30	3.4	897	10	1.1	30	3.4	-1	6,217
SUM_OP	44.85	785	10	1.3	29	3.7	785	10	1.3	29	3.7	0	6,183
WIN_T10	66.31	1,047	42	4.0	46	4.4	1,047	42	4.0	46	4.4	0	5,444
WIN_P	53.86	1,049	47	4.5	51	4.9	1,049	47	4.5	51	4.9	0	5,470
WIN_OP	42.11	935	47	5.0	50	5.3	935	47	5.0	50	5.3	0	5,387

Scenario: 1.1 But-for-Case, Price +10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	6,930	234	3.4	777	11.2	6,933	237	3.4	777	11.2	-5	5,580
SF_P	56.09	6,766	235	3.5	779	11.5	6,770	238	3.5	779	11.5	-5	5,568
SF_OP	42.17	5,583	236	4.2	805	14.4	5,587	240	4.3	805	14.4	-7	5,245
SUM_T1	86.41	8,446	607	7.2	830	9.8	8,461	622	7.3	830	9.8	-15	5,150
SUM_T10	74.71	8,147	608	7.5	829	10.2	8,161	622	7.6	829	10.2	-14	5,012
SUM_P	60.73	7,799	609	7.8	830	10.6	7,811	622	8.0	830	10.6	-13	4,852
SUM_OP	43.09	6,548	624	9.5	832	12.7	6,549	626	9.6	832	12.7	-2	4,513
WIN_T10	55.59	6,469	132	2.0	564	8.7	6,471	134	2.1	564	8.7	-4	6,456
WIN_P	52.58	6,325	164	2.6	569	9.0	6,325	164	2.6	569	9.0	0	6,833
WIN_OP	42.17	5,782	140	2.4	568	9.8	5,785	143	2.5	568	9.8	-5	6,578

FPL/Vandolah

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	12,944	194	1.5	7,723	59.7	12,169	112	0.9	7,152	58.8	-53	3,935
SF_P	30.55	6,486	112	1.7	4,789	73.8	6,486	112	1.7	4,789	73.8	0	5,560
SF_OP	28.33	3,706	112	3.0	1,466	39.6	3,706	112	3.0	1,466	39.6	0	2,624
SUM_T1	56.09	14,049	114	0.8	8,862	63.1	13,457	114	0.8	8,270	61.5	-168	4,191
SUM_T10	49.74	13,611	114	0.8	8,424	61.9	13,020	114	0.9	7,833	60.2	-174	4,062
SUM_P	34.67	7,869	114	1.5	5,033	64.0	7,869	114	1.5	5,033	64.0	0	4,410
SUM_OP	29.40	2,895	114	4.0	1,511	52.2	2,895	114	4.0	1,511	52.2	0	3,233
WIN_T10	44.40	10,623	140	1.3	5,610	52.8	10,623	140	1.3	5,610	52.8	0	3,404
WIN_P	31.21	4,795	141	2.9	2,868	59.8	4,795	141	2.9	2,868	59.8	0	3,931
WIN_OP	31.24	5,502	135	2.5	2,502	45.5	5,502	135	2.5	2,502	45.5	0	3,098

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	2,589	24	0.9	1	0.0	2,589	24	0.9	1	0.0	0	4,896
SF_P	43.61	2,577	24	0.9	1	0.0	2,577	24	0.9	1	0.0	0	4,920
SF_OP	29.75	1,534	24	1.6	0	0.0	1,534	24	1.6	0	0.0	0	4,318
SUM_T1	36.01	2,299	31	1.3	2	0.1	2,299	31	1.3	2	0.1	0	4,502
SUM_T10	66.19	3,464	31	0.9	2	0.0	3,464	31	0.9	2	0.0	0	4,706
SUM_P	46.99	3,118	31	1.0	1	0.0	3,118	31	1.0	1	0.0	0	4,806
SUM_OP	35.80	2,196	31	1.4	0	0.0	2,196	31	1.4	0	0.0	0	4,711
WIN_T10	38.56	2,558	28	1.1	0	0.0	2,558	28	1.1	0	0.0	0	4,673
WIN_P	47.53	2,928	28	0.9	0	0.0	2,928	28	0.9	0	0.0	0	4,992
WIN_OP	39.65	2,658	28	1.0	0	0.0	2,658	28	1.0	0	0.0	0	4,808

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	29,244	27,078	92.6	382	1.3	29,244	27,078	92.6	382	1.3	0	8,586
SF_P	33.87	28,068	25,910	92.3	338	1.2	28,068	25,910	92.3	338	1.2	0	8,535
SF_OP	30.71	24,812	22,886	92.2	0	0.0	24,812	22,886	92.2	0	0.0	0	8,524
SUM_T1	54.18	35,300	33,750	95.6	0	0.0	36,125	34,575	95.7	0	0.0	19	9,166
SUM_T10	43.27	32,615	31,303	96.0	0	0.0	32,951	31,639	96.0	0	0.0	8	9,225
SUM_P	39.92	28,219	27,096	96.0	0	0.0	28,403	27,280	96.0	0	0.0	5	9,233
SUM_OP	34.28	25,536	24,431	95.7	0	0.0	25,608	24,503	95.7	0	0.0	2	9,165
WIN_T10	36.12	28,424	26,305	92.5	23	0.1	28,424	26,305	92.5	23	0.1	0	8,578
WIN_P	35.05	28,789	26,667	92.6	114	0.4	28,789	26,667	92.6	114	0.4	0	8,593
WIN_OP	33.76	26,252	24,124	91.9	21	0.1	26,252	24,124	91.9	21	0.1	0	8,460

Secretariat

FPL/Vandolah

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	545	26	4.8	7	1.4	545	27	4.9	7	1.4	-6	5,180
SF_P	73.62	362	27	7.5	8	2.2	362	28	7.6	8	2.2	-6	3,621
SF_OP	51.78	267	29	11.0	9	3.2	267	30	11.2	9	3.2	-5	2,611
SUM_T1	48.60	526	54	10.2	9	1.7	526	54	10.3	9	1.7	-8	4,212
SUM_T10	38.41	304	54	17.8	4	1.3	306	56	18.2	4	1.2	-6	2,502
SUM_P	31.72	197	63	32.0	3	1.7	198	64	32.4	3	1.7	-1	3,290
SUM_OP	26.96	196	51	26.2	0	0.0	196	52	26.4	0	0.0	-3	3,102
WIN_T10	69.19	268	21	7.7	4	1.6	268	21	7.8	4	1.6	-5	3,118
WIN_P	61.24	268	23	8.7	5	1.7	269	24	8.8	5	1.7	-5	3,119
WIN_OP	61.06	268	20	7.5	4	1.7	268	20	7.6	4	1.6	-5	3,121

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	2,074	114	5.5	26	1.3	2,075	115	5.5	26	1.3	-9	6,531
SF_P	33.80	846	109	12.9	6	0.7	846	109	12.9	6	0.7	0	4,022
SF_OP	27.34	332	96	29.0	0	0.0	332	96	29.0	0	0.0	0	2,583
SUM_T1	56.75	2,874	175	6.1	36	1.3	2,878	179	6.2	36	1.3	-17	6,353
SUM_T10	47.95	1,542	197	12.7	10	0.6	1,544	199	12.9	10	0.6	-9	4,627
SUM_P	43.16	1,377	204	14.8	4	0.3	1,378	205	14.9	4	0.3	-6	4,240
SUM_OP	32.97	1,045	153	14.6	0	0.0	1,046	154	14.7	0	0.0	-4	3,250
WIN_T10	52.79	1,864	50	2.7	9	0.5	1,864	50	2.7	9	0.5	0	8,239
WIN_P	40.67	844	68	8.1	1	0.1	844	68	8.1	1	0.1	0	6,651
WIN_OP	38.89	840	56	6.7	5	0.5	840	56	6.7	5	0.5	0	6,648

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	2,354	0	0.0	0	0.0	2,354	0	0.0	0	0.0	0	9,388
SF_P	33.97	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	32.81	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	56.66	2,701	0	0.0	0	0.0	2,701	0	0.0	0	0.0	0	9,254
SUM_T10	57.70	2,977	0	0.0	0	0.0	2,977	0	0.0	0	0.0	0	9,322
SUM_P	47.81	2,496	0	0.0	0	0.0	2,496	0	0.0	0	0.0	0	9,455
SUM_OP	37.68	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	36.12	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	44.97	2,353	0	0.0	0	0.0	2,353	0	0.0	0	0.0	0	9,644
WIN_OP	36.43	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	45,890	652	1.4	1,771	3.9	45,890	652	1.4	1,771	3.9	0	3,951
SF_P	37.94	37,707	607	1.6	1,786	4.7	37,707	607	1.6	1,786	4.7	0	3,900
SF_OP	33.35	35,279	430	1.2	1,813	5.1	35,279	430	1.2	1,813	5.1	0	4,008
SUM_T1	67.33	53,901	892	1.7	1,057	2.0	53,910	901	1.7	1,057	2.0	-1	4,343
SUM_T10	64.09	52,981	877	1.7	1,055	2.0	52,990	885	1.7	1,055	2.0	-1	4,296
SUM_P	42.44	44,527	720	1.6	1,164	2.6	44,530	722	1.6	1,164	2.6	-1	4,329
SUM_OP	39.60	40,742	576	1.4	1,095	2.7	40,743	577	1.4	1,095	2.7	0	4,354
WIN_T10	49.82	50,333	326	0.6	1,940	3.9	50,333	326	0.6	1,940	3.9	0	3,996
WIN_P	35.41	39,068	360	0.9	1,672	4.3	39,068	360	0.9	1,672	4.3	0	3,905
WIN_OP	33.50	35,584	224	0.6	1,573	4.4	35,584	224	0.6	1,573	4.4	0	4,028

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	882	38	4.3	42	4.7	882	38	4.3	42	4.7	0	5,251
SF_P	46.13	870	22	2.5	49	5.6	870	22	2.5	49	5.6	0	5,391
SF_OP	36.87	676	23	3.4	48	7.1	676	23	3.4	48	7.1	0	5,016
SUM_T1	75.23	915	10	1.1	34	3.7	916	10	1.1	34	3.7	-3	6,018
SUM_T10	63.22	913	10	1.1	32	3.4	913	10	1.1	32	3.4	-1	6,049
SUM_P	48.98	888	10	1.2	33	3.8	888	10	1.2	33	3.8	-3	6,353
SUM_OP	36.69	459	10	2.1	30	6.6	459	10	2.2	30	6.6	-2	4,443
WIN_T10	54.25	1,042	44	4.2	52	5.0	1,042	44	4.2	52	5.0	0	5,517
WIN_P	44.06	960	29	3.0	52	5.4	960	29	3.0	52	5.4	0	5,187
WIN_OP	34.45	571	25	4.4	50	8.7	571	25	4.4	50	8.7	0	3,588

Scenario: 1.2 But-for-Case, Price -10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	6,687	236	3.5	801	12.0	6,690	239	3.6	801	12.0	-5	5,879
SF_P	45.89	6,217	242	3.9	793	12.7	6,217	242	3.9	793	12.7	0	5,634
SF_OP	34.51	5,584	240	4.3	759	13.6	5,584	240	4.3	759	13.6	0	5,258
SUM_T1	70.69	8,378	607	7.2	820	9.8	8,392	622	7.4	820	9.8	-15	5,115
SUM_T10	61.13	8,142	609	7.5	835	10.3	8,156	623	7.6	835	10.2	-15	5,022
SUM_P	49.69	7,554	625	8.3	839	11.1	7,559	629	8.3	839	11.1	-5	5,082
SUM_OP	35.25	4,491	630	14.0	748	16.7	4,493	632	14.1	748	16.6	-2	3,430
WIN_T10	45.49	6,234	196	3.1	576	9.2	6,234	196	3.1	576	9.2	0	6,801
WIN_P	43.02	6,112	218	3.6	557	9.1	6,112	218	3.6	557	9.1	0	6,747
WIN_OP	34.51	3,454	210	6.1	557	16.1	3,454	210	6.1	557	16.1	0	5,746

FPL/Vandolah

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	648	29.5	0	0.0	139	1,727
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	48.45	560	317	56.7	0	0.0	560	317	56.7	0	0.0	0	3,978
SF_OP	33.06	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	40.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	73.55	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	52.21	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	39.78	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	42.84	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	52.81	923	358	38.7	0	0.0	923	358	38.7	0	0.0	0	2,820
WIN_OP	44.06	1,027	358	34.8	0	0.0	1,027	358	34.8	0	0.0	0	2,664

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,354	2,622	78.2	0	0.0	0	6,241
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,108	2,462	79.2	0	0.0	0	6,420
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,773	5,131	88.9	0	0.0	0	7,944
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

FPL/Vandolah

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	88	22	24.5	3	2.9	88	23	26.2	0	0.4	89	1,198
SF_P	81.80	187	28	15.1	8	4.5	187	29	15.8	7	3.6	16	3,164
SF_OP	57.53	91	29	32.2	8	8.7	91	31	34.1	6	6.7	94	1,686
SUM_T1	54.00	112	10	9.3	0	0.0	112	10	9.3	0	0.0	0	917
SUM_T10	42.68	112	16	14.1	0	0.0	112	16	14.1	0	0.0	0	1,350
SUM_P	35.24	112	18	16.6	0	0.0	112	18	16.6	0	0.0	0	1,453
SUM_OP	29.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	76.88	174	22	12.9	1	0.5	174	22	12.7	1	0.5	-4	4,194
WIN_P	68.04	68	27	39.8	2	3.7	68	27	39.4	2	3.7	-24	1,889
WIN_OP	67.84	75	22	28.7	3	4.6	75	21	28.6	3	4.6	-4	1,609

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	411	102	24.8	0	0.0	411	98	23.7	0	0.0	-43	1,043
SF_P	37.56	348	54	15.5	0	0.0	348	54	15.5	0	0.0	0	1,375
SF_OP	30.38	345	44	12.8	0	0.0	345	44	12.8	0	0.0	0	1,245
SUM_T1	63.06	603	99	16.4	0	0.0	603	99	16.4	0	0.0	0	772
SUM_T10	53.28	580	88	15.2	0	0.0	580	88	15.2	0	0.0	0	765
SUM_P	47.96	533	174	32.6	0	0.0	533	174	32.6	0	0.0	0	1,488
SUM_OP	36.63	530	22	4.2	0	0.0	530	22	4.2	0	0.0	0	1,083
WIN_T10	58.66	224	61	27.1	0	0.0	224	60	26.7	0	0.0	-19	1,512
WIN_P	45.19	165	101	61.3	0	0.0	165	101	60.9	0	0.0	-43	3,901
WIN_OP	43.21	163	69	42.2	1	0.8	163	68	42.0	1	0.8	-15	2,086

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	37.74	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	36.45	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	62.95	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	64.11	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	53.12	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	41.87	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	40.13	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	49.97	476	0	0.0	0	0.0	476	0	0.0	0	0.0	0	8,683
WIN_OP	40.48	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	12,706	797	6.3	2	0.0	12,706	795	6.3	2	0.0	0	579
SF_P	42.16	13,161	765	5.8	2	0.0	13,161	764	5.8	2	0.0	0	788
SF_OP	37.05	10,238	465	4.5	0	0.0	10,238	465	4.5	0	0.0	0	630
SUM_T1	74.81	13,118	1,045	8.0	66	0.5	13,119	1,111	8.5	46	0.4	7	650
SUM_T10	71.21	13,267	1,036	7.8	224	1.7	13,268	1,102	8.3	203	1.5	7	637
SUM_P	47.16	12,806	886	6.9	1	0.0	12,806	886	6.9	1	0.0	0	678
SUM_OP	44.00	13,175	712	5.4	1	0.0	13,175	712	5.4	1	0.0	0	962
WIN_T10	55.36	17,139	456	2.7	108	0.6	17,139	456	2.7	108	0.6	0	1,030
WIN_P	39.34	12,283	364	3.0	1	0.0	12,283	363	3.0	1	0.0	0	874
WIN_OP	37.22	10,509	222	2.1	0	0.0	10,509	222	2.1	0	0.0	0	704

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	279	20	7.2	18	6.5	261	22	8.3	0	0.0	69	887
SF_P	51.25	307	24	7.9	25	8.2	307	22	7.2	25	8.2	-2	782
SF_OP	40.97	246	36	14.7	27	11.1	246	37	15.0	26	10.6	1	955
SUM_T1	83.59	234	11	4.7	18	7.6	216	13	6.0	0	0.0	51	900
SUM_T10	70.24	216	11	5.2	0	0.0	216	14	6.3	0	0.0	-4	982
SUM_P	54.42	201	4	2.2	0	0.0	201	4	2.2	0	0.0	0	1,052
SUM_OP	40.77	179	2	1.0	0	0.0	179	2	1.0	0	0.0	0	1,396
WIN_T10	60.28	401	50	12.5	0	0.0	401	49	12.1	0	0.0	-5	1,134
WIN_P	48.96	508	6	1.2	20	4.0	508	6	1.2	20	4.0	0	1,662
WIN_OP	38.28	306	3	1.1	0	0.0	306	3	1.1	0	0.0	0	942

Scenario: 2.0 Alternate Case
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	2,168	210	9.7	0	0.0	2,168	374	17.2	0	0.0	114	2,144
SF_P	50.99	2,803	272	9.7	186	6.6	2,803	272	9.7	186	6.6	0	3,325
SF_OP	38.34	2,375	282	11.9	0	0.0	2,375	282	11.9	0	0.0	0	3,097
SUM_T1	78.55	2,817	518	18.4	0	0.0	2,81[illegible]	662	23.5	0	0.0	65	[illegible],805
SUM_T10	67.92	2,807	549	19.5	0	0.0	2,808	694	24.7	0	0.0	179	1,841
SUM_P	55.21	3,236	600	18.5	0	0.0	3,236	600	18.5	0	0.0	0	2,612
SUM_OP	39.17	2,677	608	22.7	0	0.0	2,677	608	22.7	0	0.0	0	2,089
WIN_T10	50.54	2,338	241	10.3	0	0.0	2,338	238	10.2	0	0.0	-2	5,703
WIN_P	47.80	3,099	271	8.7	5	0.2	3,099	271	8.7	5	0.2	0	6,609
WIN_OP	38.34	2,866	258	9.0	0	0.0	2,866	258	9.0	0	0.0	0	6,370

FPL/Vandolah

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	2,196	662	30.1	0	0.0	384	1,776
SF_P	37.33	1,730	86	5.0	636	36.8	1,730	86	5.0	636	36.8	0	2,351
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,525	398	15.7	928	36.7	-304	2,252
SUM_T1	68.55	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_T10	60.80	1,434	0	0.0	0	0.0	2,025	592	29.2	0	0.0	-265	1,976
SUM_P	42.37	1,032	0	0.0	0	0.0	1,032	0	0.0	0	0.0	0	3,256
SUM_OP	35.94	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	54.26	2,327	363	15.6	0	0.0	2,327	357	15.3	0	0.0	-6	1,215
WIN_P	38.15	1,633	248	15.2	180	11.0	1,633	248	15.2	180	11.0	0	1,781
WIN_OP	38.18	2,796	573	20.5	370	13.2	2,796	573	20.5	370	13.2	0	1,717

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	53.30	639	317	49.7	0	0.0	639	317	49.7	0	0.0	0	3,259
SF_OP	36.37	480	317	66.1	0	0.0	480	317	66.1	0	0.0	0	5,280
SUM_T1	44.01	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_T10	80.91	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	57.43	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	43.76	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	47.12	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	58.09	1,016	358	35.2	0	0.0	1,016	358	35.2	0	0.0	0	2,623
WIN_OP	48.47	1,164	358	30.7	0	0.0	1,164	358	30.7	0	0.0	0	2,821

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,358	2,742	62.9	0	0.0	-172	4,318
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,262	7,881	85.1	0	0.0	-49	7,312
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,406	6,092	82.3	0	0.0	-29	6,823
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	3,354	2,622	78.2	0	0.0	0	6,241
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,108	2,462	79.2	0	0.0	0	6,420
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,142	5,501	89.6	0	0.0	0	8,058
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,092	5,620	92.3	0	0.0	0	8,531
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	9,317	7,745	83.1	0	0.0	-77	6,964
WIN_P	42.83	12,693	11,138	87.8	0	0.0	12,501	10,946	87.6	0	0.0	-32	7,694
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,207	10,668	87.4	91	0.7	-14	7,657

FPL/Vandolah

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	88	19	21.9	3	3.1	88	21	23.4	1	0.9	74	1,355
SF_P	89.98	187	27	14.4	8	4.2	187	28	15.1	6	3.4	15	3,169
SF_OP	63.28	91	26	29.0	9	9.6	91	28	30.7	7	7.8	70	1,573
SUM_T1	59.40	113	23	20.2	0	0.0	113	23	20.2	0	0.0	0	924
SUM_T10	46.95	112	15	13.5	0	0.0	112	15	13.5	0	0.0	0	1,133
SUM_P	38.76	112	18	16.2	0	0.0	112	18	16.2	0	0.0	0	1,401
SUM_OP	32.96	111	15	13.2	0	0.0	111	15	13.2	0	0.0	0	1,130
WIN_T10	84.57	174	20	11.5	1	0.6	174	20	11.3	1	0.6	-3	4,204
WIN_P	74.84	177	24	13.5	3	1.9	177	24	13.4	3	1.9	-2	4,284
WIN_OP	74.62	184	20	11.0	3	1.8	184	20	10.9	3	1.8	-1	4,458

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	411	98	23.9	0	0.0	411	103	25.0	0	0.0	44	1,067
SF_P	41.32	349	226	64.6	0	0.0	349	223	63.9	0	0.0	-76	4,226
SF_OP	33.42	346	137	39.6	0	0.0	346	133	38.5	0	0.0	-69	1,961
SUM_T1	69.37	604	112	18.6	0	0.0	604	128	21.2	0	0.0	78	883
SUM_T10	58.61	604	143	23.7	0	0.0	604	143	23.7	0	0.0	0	971
SUM_P	52.76	578	189	32.6	0	0.0	578	189	32.6	0	0.0	0	1,423
SUM_OP	40.29	531	221	41.6	0	0.0	531	221	41.6	0	0.0	0	2,089
WIN_T10	64.53	224	58	25.7	0	0.0	224	57	25.3	0	0.0	-16	1,491
WIN_P	49.71	165	74	45.1	0	0.0	165	74	44.7	0	0.0	-36	2,285
WIN_OP	47.53	163	61	37.5	2	1.3	163	61	37.3	2	1.3	-10	1,849

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	41.51	145	0	0.0	0	0.0	145	0	0.0	0	0.0	0	4,941
SF_OP	40.10	269	0	0.0	0	0.0	269	0	0.0	0	0.0	0	8,400
SUM_T1	69.25	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	70.52	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	58.43	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	46.06	250	0	0.0	0	0.0	250	0	0.0	0	0.0	0	8,150
WIN_T10	44.14	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	54.97	619	0	0.0	0	0.0	619	0	0.0	0	0.0	0	8,973
WIN_OP	44.53	877	0	0.0	0	0.0	877	0	0.0	0	0.0	0	9,668

FPL/Vandolah

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	13,442	793	5.9	2	0.0	13,600	950	7.0	2	0.0	1	587
SF_P	46.38	15,847	790	5.0	4	0.0	15,847	789	5.0	4	0.0	0	1,120
SF_OP	40.76	13,455	612	4.5	78	0.6	13,455	612	4.5	78	0.6	0	885
SUM_T1	82.29	13,320	1,045	7.8	68	0.5	13,322	1,111	8.3	46	0.3	7	638
SUM_T10	78.33	13,725	1,036	7.5	231	1.7	13,726	1,102	8.0	202	1.5	6	617
SUM_P	51.88	14,516	889	6.1	1	0.0	14,516	889	6.1	1	0.0	0	963
SUM_OP	48.40	14,446	709	4.9	83	0.6	14,446	775	5.4	17	0.1	4	1,269
WIN_T10	60.90	19,897	456	2.3	112	0.6	19,897	456	2.3	112	0.6	0	1,231
WIN_P	43.27	16,598	547	3.3	1	0.0	16,598	547	3.3	1	0.0	0	1,239
WIN_OP	40.94	15,177	412	2.7	171	1.1	15,177	412	2.7	171	1.1	0	1,027

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	279	22	7.8	21	7.5	279	24	8.4	18	6.5	1	823
SF_P	56.38	307	35	11.5	26	8.6	307	38	12.3	23	7.6	4	769
SF_OP	45.07	322	36	11.1	27	8.3	322	39	12.1	23	7.2	7	1,069
SUM_T1	91.95	234	11	4.7	18	7.6	216	13	6.0	0	0.0	50	884
SUM_T10	77.26	234	12	4.9	18	7.6	216	14	6.3	0	0.0	53	917
SUM_P	59.86	219	12	5.5	18	8.4	202	15	7.2	0	0.0	27	769
SUM_OP	44.85	197	10	5.1	18	9.1	197	10	5.1	18	9.1	0	924
WIN_T10	66.31	401	51	12.6	0	0.0	401	50	12.4	0	0.0	-4	1,123
WIN_P	53.86	508	46	9.1	19	3.7	508	44	8.8	19	3.7	-2	1,691
WIN_OP	42.11	428	52	12.0	22	5.1	428	51	11.9	22	5.1	-2	1,466

Scenario: 2.1 Alternate Case, Price +10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	2,174	214	9.8	0	0.0	2,174	372	17.1	0	0.0	117	2,121
SF_P	56.09	3,177	262	8.3	256	8.1	3,177	353	11.1	165	5.2	17	3,769
SF_OP	42.17	2,375	265	11.2	289	12.2	2,375	375	15.8	179	7.5	34	3,125
SUM_T1	86.41	2,817	515	18.3	0	0.0	2,818	659	23.4	0	0.0	163	1,799
SUM_T10	74.71	2,807	550	19.6	4	0.1	2,808	695	24.7	0	0.0	181	1,842
SUM_P	60.73	3,446	585	17.0	148	4.3	3,446	741	21.5	0	0.0	154	2,595
SUM_OP	43.09	2,677	602	22.5	0	0.0	2,677	602	22.5	0	0.0	0	2,078
WIN_T10	55.59	2,572	184	7.2	0	0.0	2,572	181	7.0	0	0.0	-1	5,092
WIN_P	52.58	3,099	265	8.6	5	0.2	3,099	265	8.6	5	0.2	0	6,606
WIN_OP	42.17	2,866	250	8.7	10	0.3	2,866	249	8.7	10	0.3	0	6,365

FPL/Vandolah

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	2,193	604	27.6	0	0.0	48	1,614
SF_P	30.55	1,046	53	5.1	0	0.0	1,046	53	5.1	0	0.0	0	2,512
SF_OP	28.33	817	44	5.3	0	0.0	817	44	5.3	0	0.0	0	3,510
SUM_T1	56.09	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_T10	49.74	1,432	0	0.0	0	0.0	2,024	592	29.2	0	0.0	-267	1,980
SUM_P	34.67	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	29.40	557	0	0.0	0	0.0	557	0	0.0	0	0.0	0	8,611
WIN_T10	44.40	2,190	398	18.2	0	0.0	2,190	389	17.8	0	0.0	-10	1,309
WIN_P	31.21	1,096	72	6.5	0	0.0	1,096	72	6.5	0	0.0	0	2,273
WIN_OP	31.24	1,006	46	4.6	0	0.0	1,006	46	4.6	0	0.0	0	2,513

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	43.61	519	317	61.1	0	0.0	519	317	61.1	0	0.0	0	4,563
SF_OP	29.75	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	36.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	66.19	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	46.99	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	35.80	196	0	0.0	0	0.0	196	0	0.0	0	0.0	0	8,289
WIN_T10	38.56	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	47.53	820	358	43.6	0	0.0	820	358	43.6	0	0.0	0	2,894
WIN_OP	39.65	823	358	43.5	0	0.0	823	358	43.5	0	0.0	0	2,948

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	895	270	30.2	0	0.0	-890	1,675
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,191	5,631	91.0	0	0.0	-49	8,288
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,236	5,731	91.9	0	0.0	-18	8,461
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	3,221	2,502	77.7	0	0.0	0	6,173
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	1,792	1,310	73.1	0	0.0	0	5,584
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,198	2,894	90.5	0	0.0	0	8,242
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,020	5,258	87.3	0	0.0	-12	7,666
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,166	9,388	92.3	0	0.0	-26	8,537
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	9,984	9,268	92.8	0	0.0	-10	8,626

FPL/Vandolah

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	88	22	25.0	3	3.0	88	24	26.7	0	0.4	91	1,186
SF_P	73.62	187	29	15.8	8	4.5	187	31	16.5	7	3.6	18	3,169
SF_OP	51.78	92	35	38.7	10	10.4	92	38	41.1	7	7.8	149	1,956
SUM_T1	48.60	112	13	11.8	0	0.0	112	13	11.8	0	0.0	0	1,017
SUM_T10	38.41	112	18	16.4	0	0.0	112	18	16.4	0	0.0	0	1,591
SUM_P	31.72	112	19	16.8	0	0.0	112	19	16.8	0	0.0	0	1,486
SUM_OP	26.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	69.19	65	25	38.9	0	0.0	65	25	38.3	0	0.0	-41	1,918
WIN_P	61.24	68	33	48.2	2	2.4	68	33	47.8	2	2.4	-34	2,492
WIN_OP	61.06	75	24	31.5	3	3.5	75	24	31.4	3	3.5	-6	1,672

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	411	104	25.4	0	0.0	411	99	24.1	0	0.0	-50	1,052
SF_P	33.80	347	55	15.8	0	0.0	347	55	15.8	0	0.0	0	1,431
SF_OP	27.34	345	46	13.2	0	0.0	345	46	13.2	0	0.0	0	1,331
SUM_T1	56.75	603	104	17.3	0	0.0	603	104	17.3	0	0.0	0	776
SUM_T10	47.95	535	50	9.3	0	0.0	535	50	9.3	0	0.0	0	914
SUM_P	43.16	533	151	28.3	0	0.0	533	151	28.3	0	0.0	0	1,333
SUM_OP	32.97	529	43	8.2	0	0.0	529	43	8.2	0	0.0	0	960
WIN_T10	52.79	176	72	40.8	0	0.0	176	71	40.2	0	0.0	-43	1,954
WIN_P	40.67	165	104	62.6	0	0.0	165	102	61.9	0	0.0	-84	4,051
WIN_OP	38.89	163	91	55.6	0	0.0	163	90	55.5	0	0.0	-19	3,278

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	33.97	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	32.81	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	56.66	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	57.70	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	47.81	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	37.68	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	36.12	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	44.97	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	8,207
WIN_OP	36.43	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	11,947	796	6.7	2	0.0	11,947	791	6.6	2	0.0	0	571
SF_P	37.94	9,664	617	6.4	2	0.0	9,664	615	6.4	2	0.0	0	675
SF_OP	33.35	9,572	428	4.5	0	0.0	9,572	428	4.5	0	0.0	0	791
SUM_T1	67.33	12,836	1,052	8.2	1	0.0	12,837	1,118	8.7	1	0.0	7	666
SUM_T10	64.09	12,802	1,047	8.2	1	0.0	12,803	1,113	8.7	1	0.0	8	668
SUM_P	42.44	10,604	840	7.9	1	0.0	10,604	840	7.9	1	0.0	0	560
SUM_OP	39.60	10,529	718	6.8	0	0.0	10,529	718	6.8	0	0.0	0	620
WIN_T10	49.82	14,197	459	3.2	0	0.0	14,197	459	3.2	0	0.0	0	780
WIN_P	35.41	9,384	283	3.0	1	0.0	9,384	283	3.0	1	0.0	0	808
WIN_OP	33.50	8,067	218	2.7	0	0.0	8,067	216	2.7	0	0.0	0	861

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	261	15	5.6	0	0.0	261	17	6.4	0	0.0	-3	906
SF_P	46.13	289	12	4.2	0	0.1	289	12	4.2	0	0.1	0	797
SF_OP	36.87	228	4	1.6	0	0.0	228	4	1.6	0	0.0	0	867
SUM_T1	75.23	216	11	5.1	0	0.0	216	13	6.1	0	0.0	-3	930
SUM_T10	63.22	216	6	2.9	0	0.1	216	9	4.2	0	0.1	-8	909
SUM_P	48.98	202	5	2.6	0	0.1	202	5	2.6	0	0.1	0	852
SUM_OP	36.69	180	3	1.8	0	0.1	180	3	1.8	0	0.1	0	983
WIN_T10	54.25	401	40	9.9	0	0.0	401	37	9.2	0	0.0	-1	1,302
WIN_P	44.06	403	9	2.2	0	0.1	403	9	2.2	0	0.1	0	1,417
WIN_OP	34.45	279	5	1.8	0	0.1	279	5	1.8	0	0.1	0	1,980

Scenario: 2.2 Alternate Case, Price -10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	1,931	213	11.0	0	0.0	1,931	208	10.8	0	0.0	-3	2,235
SF_P	45.89	2,626	282	10.7	0	0.0	2,626	282	10.7	0	0.0	0	3,548
SF_OP	34.51	2,376	246	10.3	0	0.0	2,376	245	10.3	0	0.0	0	3,166
SUM_T1	70.69	2,747	514	18.	0	0.0	2,74	659	24.0	0	0.0	172	1,732
SUM_T10	61.13	2,800	543	19.4	0	0.0	2,800	692	24.7	0	0.0	180	1,858
SUM_P	49.69	3,197	614	19.2	0	0.0	3,197	614	19.2	0	0.0	0	2,693
SUM_OP	35.25	1,044	50	4.8	0	0.0	1,044	50	4.8	0	0.0	0	2,608
WIN_T10	45.49	2,338	228	9.8	0	0.0	2,338	228	9.8	0	0.0	0	5,697
WIN_P	43.02	2,888	261	9.0	0	0.0	2,888	261	9.0	0	0.0	0	6,396
WIN_OP	34.51	540	263	48.7	0	0.0	540	262	48.5	0	0.0	-21	3,318

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FPL/Vandolah

Scenario: 1.0 Alternate Case

Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	13,298	195	1.5	8,077	60.7	13,297	766	5.8	7,505	56.4	-472	3,622
SF_P	33.94	8,913	112	1.3	5,538	62.1	8,913	112	1.3	5,538	62.1	0	4,175
SF_OP	31.48	7,121	112	1.6	4,300	60.4	7,121	112	1.6	4,300	60.4	0	3,986
SUM_T1	62.32	14,675	114	0.8	9,486	64.6	14,675	706	4.8	8,895	60.6	-482	4,045
SUM_T10	55.27	14,084	114	0.8	8,897	63.2	14,084	706	5.0	8,306	59.0	-489	3,880
SUM_P	38.52	11,044	114	1.0	6,922	62.7	11,044	114	1.0	6,922	62.7	0	4,298
SUM_OP	32.67	6,335	114	1.8	3,586	56.6	6,335	114	1.8	3,586	56.6	0	3,671
WIN_T10	49.33	10,978	140	1.3	5,964	54.3	10,978	139	1.3	5,964	54.3	0	3,528
WIN_P	34.68	8,204	139	1.7	4,891	59.6	8,203	138	1.7	4,891	59.6	1	4,041
WIN_OP	34.71	9,198	146	1.6	5,050	54.9	9,198	146	1.6	5,050	54.9	0	3,564

Scenario: 1.0 Alternate Case

Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	48.45	2,666	24	0.9	1	0.0	2,666	24	0.9	1	0.0	0	5,022
SF_OP	33.06	1,812	24	1.3	0	0.0	1,812	24	1.3	0	0.0	0	4,817
SUM_T1	40.01	2,411	31	1.3	2	0.1	2,411	31	1.3	2	0.1	0	4,650
SUM_T10	73.55	3,492	31	0.9	2	0.0	3,492	31	0.9	2	0.0	0	4,728
SUM_P	52.21	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	39.78	2,424	31	1.3	0	0.0	2,424	31	1.3	0	0.0	0	4,992
WIN_T10	42.84	2,904	28	1.0	0	0.0	2,904	28	1.0	0	0.0	0	5,038
WIN_P	52.81	3,032	28	0.9	0	0.0	3,032	28	0.9	0	0.0	0	5,097
WIN_OP	44.06	2,861	28	1.0	0	0.0	2,861	28	1.0	0	0.0	0	5,022

Scenario: 1.0 Alternate Case

Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	30,951	28,608	92.4	494	1.6	30,691	28,348	92.4	494	1.6	-12	8,543
SF_P	37.63	29,246	27,059	92.5	306	1.0	29,054	26,867	92.5	306	1.1	-9	8,564
SF_OP	34.12	25,065	22,913	91.4	490	2.0	24,989	22,837	91.4	490	2.0	-5	8,368
SUM_T1	60.20	35,433	33,870	95.6	0	0.0	35,433	33,870	95.6	0	0.0	0	9,143
SUM_T10	48.08	33,932	32,455	95.6	0	0.0	33,932	32,455	95.6	0	0.0	0	9,155
SUM_P	44.35	30,793	29,333	95.3	0	0.0	30,793	29,333	95.3	0	0.0	0	9,081
SUM_OP	38.09	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	40.13	30,943	28,595	92.4	247	0.8	30,671	28,323	92.3	247	0.8	-12	8,539
WIN_P	38.94	28,801	26,664	92.6	132	0.5	28,609	26,472	92.5	132	0.5	-9	8,575
WIN_OP	37.51	26,267	24,124	91.8	345	1.3	26,187	24,044	91.8	345	1.3	-4	8,445

FPL/Vandolah

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	546	26	4.8	8	1.4	545	27	4.9	7	1.3	4	5,181
SF_P	81.80	363	27	7.5	8	2.2	362	27	7.6	8	2.1	4	3,622
SF_OP	57.53	267	27	10.2	8	3.0	267	28	10.4	7	2.8	4	2,612
SUM_T1	54.00	526	44	8.4	11	2.1	526	44	8.4	11	2.1	0	4,213
SUM_T10	42.68	308	57	18.4	5	1.8	308	57	18.4	5	1.8	0	2,489
SUM_P	35.24	302	64	21.0	3	1.1	302	64	21.0	3	1.1	0	2,619
SUM_OP	29.96	199	30	14.9	0	0.0	199	30	14.9	0	0.0	0	2,984
WIN_T10	76.88	377	20	5.3	5	1.2	377	20	5.2	5	1.2	4	4,227
WIN_P	68.04	268	22	8.1	5	1.7	268	22	8.0	5	1.7	2	3,115
WIN_OP	67.84	268	19	7.2	5	1.8	268	19	7.2	5	1.8	1	3,117

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	2,558	108	4.2	25	1.0	2,557	108	4.2	25	1.0	5	7,122
SF_P	37.56	1,009	166	16.4	4	0.4	1,007	164	16.3	4	0.4	10	4,737
SF_OP	30.38	841	103	12.2	0	0.0	840	102	12.1	0	0.0	7	4,052
SUM_T1	63.06	2,876	168	5.8	38	1.3	2,876	168	5.8	38	1.3	0	6,356
SUM_T10	53.28	2,169	178	8.2	29	1.3	2,169	178	8.2	29	1.3	0	5,540
SUM_P	47.96	1,857	188	10.1	18	0.9	1,857	188	10.1	18	0.9	0	5,333
SUM_OP	36.63	1,052	184	17.4	0	0.0	1,052	184	17.4	0	0.0	0	3,251
WIN_T10	58.66	1,911	47	2.5	8	0.4	1,911	47	2.5	8	0.4	4	7,846
WIN_P	45.19	1,168	60	5.2	2	0.1	1,168	60	5.1	2	0.1	5	7,468
WIN_OP	43.21	1,002	50	5.0	10	1.0	1,002	50	5.0	10	1.0	2	7,114

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	2,626	0	0.0	0	0.0	2,626	0	0.0	0	0.0	0	9,451
SF_P	37.74	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	36.45	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	62.95	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	64.11	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	53.12	2,619	0	0.0	0	0.0	2,619	0	0.0	0	0.0	0	9,480
SUM_OP	41.87	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	40.13	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	49.97	2,487	0	0.0	0	0.0	2,487	0	0.0	0	0.0	0	9,663
WIN_OP	40.48	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	47,746	652	1.4	1,761	3.7	47,743	650	1.4	1,761	3.7	0	4,014
SF_P	42.16	42,006	602	1.4	1,737	4.1	42,004	600	1.4	1,737	4.1	0	3,871
SF_OP	37.05	35,446	428	1.2	1,789	5.0	35,446	427	1.2	1,789	5.0	0	4,007
SUM_T1	74.81	55,390	901	1.6	1,092	2.0	55,390	920	1.7	1,072	1.9	0	4,393
SUM_T10	71.21	55,090	884	1.6	1,094	2.0	55,090	904	1.6	1,074	2.0	0	4,414
SUM_P	47.16	46,884	724	1.5	1,027	2.2	46,884	724	1.5	1,027	2.2	0	4,362
SUM_OP	44.00	43,583	577	1.3	958	2.2	43,583	577	1.3	958	2.2	0	4,365
WIN_T10	55.36	52,967	325	0.6	1,944	3.7	52,966	324	0.6	1,944	3.7	0	4,074
WIN_P	39.34	41,977	359	0.9	1,678	4.0	41,976	358	0.9	1,678	4.0	0	4,055
WIN_OP	37.22	38,073	221	0.6	1,884	4.9	38,072	220	0.6	1,884	4.9	0	4,014

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	883	36	4.1	41	4.7	882	37	4.2	41	4.6	3	5,242
SF_P	51.25	873	42	4.8	45	5.2	873	41	4.7	45	5.2	4	5,350
SF_OP	40.97	760	40	5.3	43	5.6	760	40	5.3	42	5.6	2	5,296
SUM_T1	83.59	916	10	1.1	34	3.7	916	11	1.2	33	3.6	0	6,011
SUM_T10	70.24	916	10	1.1	34	3.7	916	11	1.2	34	3.7	0	6,018
SUM_P	54.42	896	10	1.2	30	3.4	896	10	1.2	30	3.4	0	6,231
SUM_OP	40.77	699	10	1.4	31	4.4	699	10	1.4	31	4.4	0	5,853
WIN_T10	60.28	1,048	43	4.1	46	4.4	1,048	42	4.1	46	4.4	4	5,445
WIN_P	48.96	1,036	23	2.3	51	4.9	1,036	23	2.2	51	4.9	6	5,607
WIN_OP	38.28	816	23	2.8	46	5.6	815	23	2.8	46	5.6	3	5,111

Scenario: 1.0 Alternate Case
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	6,929	240	3.5	781	11.3	6,927	259	3.7	760	11.0	-1	5,588
SF_P	50.99	6,396	241	3.8	792	12.4	6,395	240	3.7	792	12.4	3	5,447
SF_OP	38.34	5,587	242	4.3	784	14.0	5,586	241	4.3	784	14.0	1	5,242
SUM_T1	78.55	8,461	622	7.3	829	9.8	8,461	637	7.5	814	9.6	-1	5,150
SUM_T10	67.92	8,163	621	7.6	824	10.1	8,163	638	7.8	807	9.9	-1	5,008
SUM_P	55.21	7,602	624	8.2	840	11.1	7,602	624	8.2	840	11.1	0	5,023
SUM_OP	39.17	6,546	627	9.6	815	12.5	6,546	627	9.6	815	12.5	0	4,513
WIN_T10	50.54	6,237	161	2.6	568	9.1	6,235	159	2.6	568	9.1	3	6,794
WIN_P	47.80	6,326	201	3.2	578	9.1	6,324	200	3.2	578	9.1	3	6,840
WIN_OP	38.34	5,784	174	3.0	566	9.8	5,784	174	3.0	566	9.8	1	6,582

FPL/Vandolah

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	13,858	190	1.4	8,635	62.3	13,858	761	5.5	8,064	58.2	-468	3,788
SF_P	37.33	10,902	112	1.0	6,592	60.5	10,902	112	1.0	6,592	60.5	0	4,094
SF_OP	34.63	10,716	112	1.0	6,246	58.3	10,716	256	2.4	6,103	57.0	-149	3,790
SUM_T1	68.55	14,810	114	0.8	9,622	65.0	14,810	706	4.8	9,030	61.0	-481	4,082
SUM_T10	60.80	14,558	114	0.8	9,369	64.4	14,558	706	4.8	8,778	60.3	-484	4,012
SUM_P	42.37	11,327	114	1.0	6,922	61.1	11,327	114	1.0	6,922	61.1	0	4,153
SUM_OP	35.94	9,461	114	1.2	5,191	54.9	9,461	114	1.2	5,191	54.9	0	3,593
WIN_T10	54.26	11,350	140	1.2	6,345	55.9	11,350	140	1.2	6,345	55.9	0	3,662
WIN_P	38.15	9,444	141	1.5	5,416	57.3	9,444	141	1.5	5,416	57.4	0	3,760
WIN_OP	38.18	9,720	143	1.5	5,050	52.0	9,720	143	1.5	5,050	52.0	0	3,421

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	53.30	2,745	24	0.9	1	0.0	2,745	24	0.9	1	0.0	0	4,939
SF_OP	36.37	2,015	24	1.2	0	0.0	2,015	24	1.2	0	0.0	0	5,124
SUM_T1	44.01	2,416	31	1.3	2	0.1	2,416	31	1.3	2	0.1	0	4,631
SUM_T10	80.91	3,507	31	0.9	2	0.0	3,507	31	0.9	2	0.0	0	4,740
SUM_P	57.43	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	43.76	2,623	31	1.2	0	0.0	2,623	31	1.2	0	0.0	0	5,244
WIN_T10	47.12	3,008	28	0.9	0	0.0	3,008	28	0.9	0	0.0	0	5,143
WIN_P	58.09	3,124	28	0.9	0	0.0	3,124	28	0.9	0	0.0	0	5,005
WIN_OP	48.47	2,998	28	0.9	0	0.0	2,998	28	0.9	0	0.0	0	5,161

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	31,999	29,493	92.2	626	2.0	31,739	29,233	92.1	626	2.0	-12	8,496
SF_P	41.39	30,664	28,166	91.9	483	1.6	30,472	27,974	91.8	483	1.6	-9	8,440
SF_OP	37.53	25,672	23,490	91.5	590	2.3	25,596	23,414	91.5	590	2.3	-5	8,384
SUM_T1	66.22	35,433	33,870	95.6	0	0.0	35,433	33,870	95.6	0	0.0	0	9,143
SUM_T10	52.89	33,932	32,455	95.6	0	0.0	33,932	32,455	95.6	0	0.0	0	9,155
SUM_P	48.79	31,163	29,703	95.3	0	0.0	31,163	29,703	95.3	0	0.0	0	9,092
SUM_OP	41.90	27,370	26,092	95.3	0	0.0	27,370	26,092	95.3	0	0.0	0	9,096
WIN_T10	44.14	31,315	28,806	92.0	348	1.1	31,043	28,534	91.9	348	1.1	-13	8,461
WIN_P	42.83	30,575	28,240	92.4	300	1.0	30,383	28,048	92.3	300	1.0	-9	8,533
WIN_OP	41.26	28,028	25,727	91.8	270	1.0	27,948	25,647	91.8	270	1.0	-4	8,434

FPL/Vandolah

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	546	26	4.7	7	1.4	545	26	4.8	7	1.3	4	5,181
SF_P	89.98	363	27	7.3	8	2.2	362	27	7.4	8	2.1	4	3,623
SF_OP	63.28	267	26	9.8	8	3.1	267	27	10.0	8	2.9	4	2,603
SUM_T1	59.40	530	40	7.6	9	1.7	530	40	7.6	9	1.7	0	4,229
SUM_T10	46.95	526	56	10.6	8	1.6	526	56	10.6	8	1.6	0	4,211
SUM_P	38.76	305	67	22.1	2	0.7	305	67	22.1	2	0.7	0	2,629
SUM_OP	32.96	200	42	21.1	0	0.0	200	42	21.1	0	0.0	0	3,004
WIN_T10	84.57	377	19	5.1	4	1.2	377	19	5.1	4	1.2	3	4,228
WIN_P	74.84	378	21	5.5	5	1.3	378	20	5.4	5	1.3	3	4,222
WIN_OP	74.62	377	19	5.0	5	1.2	377	19	5.0	5	1.2	1	4,229

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	2,558	105	4.1	27	1.0	2,557	106	4.1	25	1.0	5	7,120
SF_P	41.32	1,168	150	12.8	6	0.5	1,167	149	12.7	6	0.5	7	5,246
SF_OP	33.42	847	143	16.9	0	0.0	847	142	16.8	0	0.0	3	4,060
SUM_T1	69.37	2,876	163	5.7	41	1.4	2,876	166	5.8	38	1.3	1	6,354
SUM_T10	58.61	2,878	174	6.0	40	1.4	2,878	174	6.0	40	1.4	0	6,352
SUM_P	52.76	2,163	177	8.2	34	1.6	2,163	177	8.2	34	1.6	0	5,546
SUM_OP	40.29	1,213	185	15.3	16	1.3	1,213	185	15.3	16	1.3	0	3,708
WIN_T10	64.53	1,911	47	2.4	8	0.4	1,911	46	2.4	8	0.4	3	7,845
WIN_P	49.71	1,489	54	3.6	5	0.3	1,488	53	3.6	5	0.3	4	7,964
WIN_OP	47.53	1,484	48	3.3	9	0.6	1,484	48	3.2	9	0.6	2	7,980

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	2,762	0	0.0	0	0.0	2,762	0	0.0	0	0.0	0	9,477
SF_P	41.51	2,211	0	0.0	0	0.0	2,211	0	0.0	0	0.0	0	9,440
SF_OP	40.10	2,175	0	0.0	0	0.0	2,175	0	0.0	0	0.0	0	9,730
SUM_T1	69.25	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	70.52	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	58.43	2,895	0	0.0	0	0.0	2,895	0	0.0	0	0.0	0	9,529
SUM_OP	46.06	2,685	0	0.0	0	0.0	2,685	0	0.0	0	0.0	0	9,755
WIN_T10	44.14	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	54.97	2,630	0	0.0	0	0.0	2,630	0	0.0	0	0.0	0	9,681
WIN_OP	44.53	2,729	0	0.0	0	0.0	2,729	0	0.0	0	0.0	0	9,862

FPL/Vandolah

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	48,203	650	1.3	1,821	3.8	48,200	699	1.4	1,770	3.7	0	3,965
SF_P	46.38	44,226	602	1.4	1,706	3.9	44,224	600	1.4	1,706	3.9	0	4,001
SF_OP	40.76	39,197	446	1.1	1,710	4.4	39,196	445	1.1	1,710	4.4	0	3,837
SUM_T1	82.29	55,621	901	1.6	1,077	1.9	55,621	920	1.7	1,058	1.9	0	4,364
SUM_T10	78.33	55,548	884	1.6	1,085	2.0	55,548	903	1.6	1,066	1.9	0	4,375
SUM_P	51.88	48,601	723	1.5	968	2.0	48,601	723	1.5	968	2.0	0	4,446
SUM_OP	48.40	45,319	574	1.3	949	2.1	45,319	601	1.3	921	2.0	0	4,501
WIN_T10	60.90	54,692	325	0.6	1,852	3.4	54,691	324	0.6	1,852	3.4	0	4,220
WIN_P	43.27	46,754	353	0.8	1,866	4.0	46,753	353	0.8	1,866	4.0	0	3,928
WIN_OP	40.94	42,454	314	0.7	1,899	4.5	42,453	314	0.7	1,899	4.5	0	3,919

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	884	35	4.0	43	4.9	884	36	4.0	42	4.8	3	5,223
SF_P	56.38	880	39	4.4	41	4.7	880	39	4.5	40	4.6	3	5,261
SF_OP	45.07	846	38	4.6	40	4.8	846	39	4.7	39	4.6	2	5,615
SUM_T1	91.95	916	10	1.1	33	3.6	916	11	1.2	33	3.6	0	6,009
SUM_T10	77.26	916	10	1.1	34	3.7	916	11	1.2	33	3.6	0	6,017
SUM_P	59.86	897	10	1.1	30	3.4	897	11	1.2	29	3.3	0	6,217
SUM_OP	44.85	785	10	1.3	29	3.7	785	10	1.3	29	3.7	0	6,183
WIN_T10	66.31	1,048	42	4.0	46	4.4	1,047	42	4.0	46	4.4	4	5,445
WIN_P	53.86	1,049	47	4.5	51	4.9	1,049	46	4.4	51	4.9	4	5,471
WIN_OP	42.11	935	47	5.0	50	5.3	935	46	5.0	50	5.3	2	5,387

Scenario: 1.1 Alternate Case, Price +10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	6,935	239	3.4	777	11.2	6,933	257	3.7	757	10.9	-1	5,576
SF_P	56.09	6,771	240	3.5	779	11.5	6,770	260	3.8	757	11.2	-2	5,563
SF_OP	42.17	5,588	241	4.3	805	14.4	5,587	268	4.8	778	13.9	-8	5,236
SUM_T1	86.41	8,461	621	7.3	830	9.8	8,461	637	7.5	814	9.6	-1	5,149
SUM_T10	74.71	8,161	621	7.6	829	10.2	8,161	637	7.8	813	10.0	-1	5,011
SUM_P	60.73	7,811	621	8.0	830	10.6	7,811	640	8.2	811	10.4	-1	4,851
SUM_OP	43.09	6,549	626	9.6	832	12.7	6,549	626	9.6	832	12.7	0	4,512
WIN_T10	55.59	6,472	134	2.1	565	8.7	6,471	132	2.0	565	8.7	2	6,456
WIN_P	52.58	6,326	164	2.6	570	9.0	6,325	163	2.6	570	9.0	2	6,833
WIN_OP	42.17	5,785	142	2.4	568	9.8	5,785	141	2.4	568	9.8	1	6,578

FPL/Vandolah

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	12,944	194	1.5	7,723	59.7	12,944	765	5.9	7,152	55.3	-474	3,513
SF_P	30.55	6,486	112	1.7	4,789	73.8	6,486	112	1.7	4,789	73.8	0	5,560
SF_OP	28.33	3,706	112	3.0	1,466	39.6	3,706	112	3.0	1,466	39.6	0	2,624
SUM_T1	56.09	14,049	114	0.8	8,862	63.1	14,049	706	5.0	8,270	58.9	-489	3,870
SUM_T10	49.74	13,611	114	0.8	8,424	61.9	13,611	706	5.2	7,833	57.5	-493	3,743
SUM_P	34.67	7,869	114	1.5	5,033	64.0	7,869	114	1.5	5,033	64.0	0	4,410
SUM_OP	29.40	2,895	114	4.0	1,511	52.2	2,895	114	4.0	1,511	52.2	0	3,233
WIN_T10	44.40	10,624	140	1.3	5,610	52.8	10,623	140	1.3	5,610	52.8	0	3,404
WIN_P	31.21	4,796	141	2.9	2,868	59.8	4,795	140	2.9	2,868	59.8	1	3,931
WIN_OP	31.24	5,502	135	2.5	2,502	45.5	5,502	135	2.5	2,502	45.5	0	3,098

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	2,589	24	0.9	1	0.0	2,589	24	0.9	1	0.0	0	4,896
SF_P	43.61	2,577	24	0.9	1	0.0	2,577	24	0.9	1	0.0	0	4,920
SF_OP	29.75	1,534	24	1.6	0	0.0	1,534	24	1.6	0	0.0	0	4,318
SUM_T1	36.01	2,299	31	1.3	2	0.1	2,299	31	1.3	2	0.1	0	4,502
SUM_T10	66.19	3,464	31	0.9	2	0.0	3,464	31	0.9	2	0.0	0	4,706
SUM_P	46.99	3,118	31	1.0	1	0.0	3,118	31	1.0	1	0.0	0	4,806
SUM_OP	35.80	2,196	31	1.4	0	0.0	2,196	31	1.4	0	0.0	0	4,711
WIN_T10	38.56	2,558	28	1.1	0	0.0	2,558	28	1.1	0	0.0	0	4,673
WIN_P	47.53	2,928	28	0.9	0	0.0	2,928	28	0.9	0	0.0	0	4,992
WIN_OP	39.65	2,658	28	1.0	0	0.0	2,658	28	1.0	0	0.0	0	4,808

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	29,244	27,078	92.6	382	1.3	28,984	26,818	92.5	382	1.3	-12	8,574
SF_P	33.87	28,068	25,910	92.3	338	1.2	27,876	25,718	92.3	338	1.2	-10	8,525
SF_OP	30.71	24,812	22,886	92.2	0	0.0	24,736	22,810	92.2	0	0.0	-4	8,520
SUM_T1	54.18	35,300	33,750	95.6	0	0.0	35,300	33,750	95.6	0	0.0	0	9,147
SUM_T10	43.27	32,615	31,303	96.0	0	0.0	32,615	31,303	96.0	0	0.0	0	9,217
SUM_P	39.92	28,219	27,096	96.0	0	0.0	28,219	27,096	96.0	0	0.0	0	9,228
SUM_OP	34.28	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	36.12	28,424	26,305	92.5	23	0.1	28,152	26,033	92.5	23	0.1	-13	8,565
WIN_P	35.05	28,789	26,667	92.6	114	0.4	28,597	26,475	92.6	114	0.4	-9	8,584
WIN_OP	33.76	26,252	24,124	91.9	21	0.1	26,172	24,044	91.9	21	0.1	-4	8,456

FPL/Vandolah

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	546	26	4.8	8	1.4	545	27	4.9	7	1.3	4	5,181
SF_P	73.62	363	28	7.6	8	2.3	362	28	7.7	8	2.1	4	3,623
SF_OP	51.78	267	30	11.0	9	3.2	267	30	11.3	8	3.0	5	2,614
SUM_T1	48.60	526	54	10.3	9	1.7	526	54	10.3	9	1.7	0	4,211
SUM_T10	38.41	306	55	18.0	4	1.3	306	55	18.0	4	1.3	0	2,497
SUM_P	31.72	198	64	32.2	3	1.7	198	64	32.2	3	1.7	0	3,276
SUM_OP	26.96	196	52	26.3	0	0.0	196	52	26.3	0	0.0	0	3,097
WIN_T10	69.19	268	21	7.7	4	1.7	268	21	7.7	4	1.7	3	3,118
WIN_P	61.24	269	23	8.7	5	1.7	269	23	8.7	5	1.7	3	3,119
WIN_OP	61.06	268	20	7.5	4	1.7	268	20	7.5	4	1.7	1	3,120

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	2,076	114	5.5	26	1.3	2,075	113	5.5	26	1.3	6	6,531
SF_P	33.80	848	110	12.9	6	0.7	846	107	12.7	6	0.7	15	4,021
SF_OP	27.34	334	97	29.0	0	0.0	332	96	28.8	0	0.0	-2	2,582
SUM_T1	56.75	2,878	176	6.1	36	1.3	2,878	176	6.1	36	1.3	0	6,353
SUM_T10	47.95	1,544	197	12.8	10	0.6	1,544	197	12.8	10	0.6	0	4,626
SUM_P	43.16	1,378	204	14.8	4	0.3	1,378	204	14.8	4	0.3	0	4,240
SUM_OP	32.97	1,046	153	14.6	0	0.0	1,046	153	14.6	0	0.0	0	3,250
WIN_T10	52.79	1,864	50	2.7	9	0.5	1,864	49	2.7	9	0.5	4	8,239
WIN_P	40.67	845	68	8.1	1	0.1	844	68	8.0	1	0.1	8	6,651
WIN_OP	38.89	841	56	6.7	5	0.5	840	56	6.7	5	0.5	3	6,648

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	2,354	0	0.0	0	0.0	2,354	0	0.0	0	0.0	0	9,388
SF_P	33.97	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	32.81	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	56.66	2,701	0	0.0	0	0.0	2,701	0	0.0	0	0.0	0	9,254
SUM_T10	57.70	2,977	0	0.0	0	0.0	2,977	0	0.0	0	0.0	0	9,322
SUM_P	47.81	2,496	0	0.0	0	0.0	2,496	0	0.0	0	0.0	0	9,455
SUM_OP	37.68	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	36.12	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	44.97	2,353	0	0.0	0	0.0	2,353	0	0.0	0	0.0	0	9,644
WIN_OP	36.43	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	45,893	654	1.4	1,771	3.9	45,890	652	1.4	1,771	3.9	0	3,951
SF_P	37.94	37,710	610	1.6	1,786	4.7	37,707	607	1.6	1,786	4.7	0	3,900
SF_OP	33.35	35,280	431	1.2	1,813	5.1	35,279	430	1.2	1,813	5.1	0	4,008
SUM_T1	67.33	53,910	901	1.7	1,057	2.0	53,910	921	1.7	1,037	1.9	0	4,343
SUM_T10	64.09	52,990	885	1.7	1,055	2.0	52,990	906	1.7	1,034	2.0	0	4,296
SUM_P	42.44	44,530	722	1.6	1,164	2.6	44,530	722	1.6	1,164	2.6	0	4,329
SUM_OP	39.60	40,743	577	1.4	1,095	2.7	40,743	577	1.4	1,095	2.7	0	4,354
WIN_T10	49.82	50,334	327	0.6	1,940	3.9	50,333	326	0.6	1,940	3.9	0	3,996
WIN_P	35.41	39,070	363	0.9	1,672	4.3	39,067	360	0.9	1,672	4.3	1	3,906
WIN_OP	33.50	35,584	225	0.6	1,573	4.4	35,584	224	0.6	1,573	4.4	0	4,028

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	882	38	4.3	42	4.7	882	38	4.3	41	4.6	4	5,251
SF_P	46.13	870	22	2.5	49	5.6	870	22	2.5	49	5.6	6	5,392
SF_OP	36.87	677	23	3.4	48	7.1	676	23	3.4	48	7.1	3	5,017
SUM_T1	75.23	916	10	1.1	34	3.7	916	11	1.2	34	3.7	0	6,018
SUM_T10	63.22	913	10	1.1	32	3.4	913	11	1.2	31	3.4	0	6,049
SUM_P	48.98	888	10	1.2	33	3.8	888	10	1.2	33	3.8	0	6,353
SUM_OP	36.69	459	10	2.2	30	6.6	459	10	2.2	30	6.6	0	4,443
WIN_T10	54.25	1,042	44	4.3	52	5.0	1,041	44	4.2	52	5.0	5	5,518
WIN_P	44.06	960	29	3.0	52	5.4	960	28	2.9	52	5.4	7	5,188
WIN_OP	34.45	571	25	4.4	50	8.7	571	25	4.4	50	8.7	4	3,589

Scenario: 1.2 Alternate Case, Price -10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	6,692	241	3.6	801	12.0	6,690	239	3.6	801	12.0	4	5,880
SF_P	45.89	6,219	243	3.9	793	12.7	6,217	242	3.9	793	12.7	3	5,634
SF_OP	34.51	5,585	241	4.3	759	13.6	5,584	240	4.3	759	13.6	2	5,258
SUM_T1	70.69	8,392	622	7.4	820	9.8	8,392	638	7.6	804	9.6	-1	5,114
SUM_T10	61.13	8,156	623	7.6	835	10.2	8,156	642	7.9	816	10.0	-1	5,021
SUM_P	49.69	7,559	629	8.3	839	11.1	7,559	629	8.3	839	11.1	0	5,082
SUM_OP	35.25	4,493	632	14.1	748	16.6	4,493	632	14.1	748	16.6	0	3,430
WIN_T10	45.49	6,236	197	3.2	576	9.2	6,234	195	3.1	576	9.2	4	6,801
WIN_P	43.02	6,113	219	3.6	557	9.1	6,112	218	3.6	557	9.1	3	6,747
WIN_OP	34.51	3,454	211	6.1	557	16.1	3,454	210	6.1	557	16.1	3	5,746

FPL/Vandolah

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	1,622	83	5.1	0	0.0	2,193	363	16.5	0	0.0	-291	1,298
SF_P	33.94	1,115	92	8.3	69	6.2	1,115	92	8.3	69	6.2	0	2,266
SF_OP	31.48	1,010	83	8.2	0	0.0	1,010	83	8.2	0	0.0	0	2,664
SUM_T1	62.32	1,434	0	0.0	0	0.0	2,025	297	14.6	0	0.0	-692	1,550
SUM_T10	55.27	1,432	0	0.0	0	0.0	2,024	297	14.7	0	0.0	-694	1,553
SUM_P	38.52	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	32.67	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	49.33	2,190	372	17.0	0	0.0	2,190	364	16.6	0	0.0	-10	1,264
WIN_P	34.68	1,633	304	18.6	180	11.0	1,633	304	18.6	180	11.0	0	1,582
WIN_OP	34.71	2,022	607	30.0	370	18.3	2,022	607	30.0	370	18.3	0	1,942

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	48.45	560	317	56.7	0	0.0	560	317	56.7	0	0.0	0	3,978
SF_OP	33.06	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	40.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	73.55	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	52.21	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	39.78	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	42.84	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	52.81	923	358	38.7	0	0.0	923	358	38.7	0	0.0	0	2,820
WIN_OP	44.06	1,027	358	34.8	0	0.0	1,027	358	34.8	0	0.0	0	2,664

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	3,339	2,055	61.5	0	0.0	3,079	1,795	58.3	0	0.0	-315	3,895
SF_P	37.63	7,560	6,967	92.2	0	0.0	7,368	6,775	91.9	0	0.0	-37	8,465
SF_OP	34.12	6,666	5,595	83.9	0	0.0	6,590	5,519	83.7	0	0.0	-30	7,078
SUM_T1	60.20	3,354	2,622	78.2	0	0.0	3,354	2,622	78.2	0	0.0	0	6,241
SUM_T10	48.08	3,108	2,462	79.2	0	0.0	3,108	2,462	79.2	0	0.0	0	6,420
SUM_P	44.35	5,773	5,131	88.9	0	0.0	5,773	5,131	88.9	0	0.0	0	7,944
SUM_OP	38.09	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	40.13	9,139	7,732	84.6	0	0.0	8,950	7,543	84.3	0	0.0	-53	7,154
WIN_P	38.94	10,503	9,576	91.2	0	0.0	10,311	9,384	91.0	0	0.0	-30	8,294
WIN_OP	37.51	10,859	9,325	85.9	0	0.0	10,779	9,245	85.8	0	0.0	-18	7,388

FPL/Vandolah

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	88	22	24.5	3	2.9	88	22	25.0	0	0.4	25	1,135
SF_P	81.80	187	28	15.1	8	4.5	187	29	15.3	7	3.6	2	3,150
SF_OP	57.53	91	29	32.2	8	8.7	91	30	33.0	6	6.7	27	1,619
SUM_T1	54.00	112	10	9.3	0	0.0	112	10	9.3	0	0.0	0	917
SUM_T10	42.68	112	16	14.1	0	0.0	112	16	14.1	0	0.0	0	1,350
SUM_P	35.24	112	18	16.6	0	0.0	112	18	16.6	0	0.0	0	1,453
SUM_OP	29.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	76.88	174	22	12.9	1	0.5	174	22	12.7	1	0.5	-4	4,194
WIN_P	68.04	68	27	39.8	2	3.7	68	27	39.4	2	3.7	-24	1,889
WIN_OP	67.84	75	22	28.7	3	4.6	75	21	28.6	3	4.6	-4	1,609

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	411	102	24.8	0	0.0	411	98	23.7	0	0.0	-43	1,043
SF_P	37.56	348	54	15.5	0	0.0	348	54	15.5	0	0.0	0	1,375
SF_OP	30.38	345	44	12.8	0	0.0	345	44	12.8	0	0.0	0	1,245
SUM_T1	63.06	603	99	16.4	0	0.0	603	99	16.4	0	0.0	0	772
SUM_T10	53.28	580	88	15.2	0	0.0	580	88	15.2	0	0.0	0	765
SUM_P	47.96	533	174	32.6	0	0.0	533	174	32.6	0	0.0	0	1,488
SUM_OP	36.63	530	22	4.2	0	0.0	530	22	4.2	0	0.0	0	1,083
WIN_T10	58.66	224	61	27.1	0	0.0	224	60	26.7	0	0.0	-19	1,512
WIN_P	45.19	165	101	61.3	0	0.0	165	101	60.9	0	0.0	-43	3,901
WIN_OP	43.21	163	69	42.2	1	0.8	163	68	42.0	1	0.8	-15	2,086

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	37.74	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	36.45	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	62.95	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	64.11	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	53.12	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	41.87	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	40.13	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	49.97	476	0	0.0	0	0.0	476	0	0.0	0	0.0	0	8,683
WIN_OP	40.48	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	12,706	797	6.3	2	0.0	12,706	795	6.3	2	0.0	0	579
SF_P	42.16	13,161	765	5.8	2	0.0	13,161	764	5.8	2	0.0	0	788
SF_OP	37.05	10,238	465	4.5	0	0.0	10,238	465	4.5	0	0.0	0	630
SUM_T1	74.81	13,118	1,045	8.0	66	0.5	13,119	1,078	8.2	46	0.4	3	646
SUM_T10	71.21	13,267	1,036	7.8	224	1.7	13,268	1,069	8.1	203	1.5	3	633
SUM_P	47.16	12,806	886	6.9	1	0.0	12,806	886	6.9	1	0.0	0	678
SUM_OP	44.00	13,175	712	5.4	1	0.0	13,175	712	5.4	1	0.0	0	962
WIN_T10	55.36	17,139	456	2.7	108	0.6	17,139	456	2.7	108	0.6	0	1,030
WIN_P	39.34	12,283	364	3.0	1	0.0	12,283	363	3.0	1	0.0	0	874
WIN_OP	37.22	10,509	222	2.1	0	0.0	10,509	222	2.1	0	0.0	0	704

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	279	20	7.2	18	6.5	261	20	7.7	0	0.0	59	877
SF_P	51.25	307	24	7.9	25	8.2	307	22	7.2	25	8.2	-2	782
SF_OP	40.97	246	36	14.7	27	11.1	246	37	15.0	26	10.6	1	955
SUM_T1	83.59	234	11	4.7	18	7.6	216	12	5.6	0	0.0	46	894
SUM_T10	70.24	216	11	5.2	0	0.0	216	12	5.8	0	0.0	-11	976
SUM_P	54.42	201	4	2.2	0	0.0	201	4	2.2	0	0.0	0	1,052
SUM_OP	40.77	179	2	1.0	0	0.0	179	2	1.0	0	0.0	0	1,396
WIN_T10	60.28	401	50	12.5	0	0.0	401	49	12.1	0	0.0	-5	1,134
WIN_P	48.96	508	6	1.2	20	4.0	508	6	1.2	20	4.0	0	1,662
WIN_OP	38.28	306	3	1.1	0	0.0	306	3	1.1	0	0.0	0	942

Scenario: 2.0 Alternate Case Mitigation Case
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	2,168	210	9.7	0	0.0	2,168	291	13.4	0	0.0	11	2,042
SF_P	50.99	2,803	272	9.7	186	6.6	2,803	272	9.7	186	6.6	0	3,325
SF_OP	38.34	2,375	282	11.9	0	0.0	2,375	282	11.9	0	0.0	0	3,097
SUM_T1	78.55	2,817	518	18.4	0	0.0	2,818	590	20.9	0	0.0	57	1,698
SUM_T10	67.92	2,807	549	19.5	0	0.0	2,808	622	22.1	0	0.0	65	1,726
SUM_P	55.21	3,236	600	18.5	0	0.0	3,236	600	18.5	0	0.0	0	2,612
SUM_OP	39.17	2,677	608	22.7	0	0.0	2,677	608	22.7	0	0.0	0	2,089
WIN_T10	50.54	2,338	241	10.3	0	0.0	2,338	238	10.2	0	0.0	-2	5,703
WIN_P	47.80	3,099	271	8.7	5	0.2	3,099	271	8.7	5	0.2	0	6,609
WIN_OP	38.34	2,866	258	9.0	0	0.0	2,866	258	9.0	0	0.0	0	6,370

FPL/Vandolah

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	1,874	96	5.1	250	13.3	2,196	377	17.2	0	0.0	-62	1,331
SF_P	37.33	1,730	86	5.0	636	36.8	1,730	86	5.0	636	36.8	0	2,351
SF_OP	34.63	2,525	256	10.1	1,071	42.4	2,525	398	15.7	928	36.7	-304	2,252
SUM_T1	68.55	1,434	0	0.0	0	0.0	2,025	297	14.6	0	0.0	-692	1,550
SUM_T10	60.80	1,434	0	0.0	0	0.0	2,025	297	14.6	0	0.0	-692	1,550
SUM_P	42.37	1,032	0	0.0	0	0.0	1,032	0	0.0	0	0.0	0	3,256
SUM_OP	35.94	767	0	0.0	0	0.0	767	0	0.0	0	0.0	0	5,291
WIN_T10	54.26	2,327	363	15.6	0	0.0	2,327	357	15.3	0	0.0	-6	1,215
WIN_P	38.15	1,633	248	15.2	180	11.0	1,633	248	15.2	180	11.0	0	1,781
WIN_OP	38.18	2,796	573	20.5	370	13.2	2,796	573	20.5	370	13.2	0	1,717

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	53.30	639	317	49.7	0	0.0	639	317	49.7	0	0.0	0	3,259
SF_OP	36.37	480	317	66.1	0	0.0	480	317	66.1	0	0.0	0	5,280
SUM_T1	44.01	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_T10	80.91	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	57.43	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	43.76	201	0	0.0	0	0.0	201	0	0.0	0	0.0	0	7,880
WIN_T10	47.12	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	58.09	1,016	358	35.2	0	0.0	1,016	358	35.2	0	0.0	0	2,623
WIN_OP	48.47	1,164	358	30.7	0	0.0	1,164	358	30.7	0	0.0	0	2,821

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	4,553	2,937	64.5	0	0.0	4,358	2,742	62.9	0	0.0	-172	4,318
SF_P	41.39	9,454	8,073	85.4	0	0.0	9,262	7,881	85.1	0	0.0	-49	7,312
SF_OP	37.53	7,482	6,168	82.4	0	0.0	7,406	6,092	82.3	0	0.0	-29	6,823
SUM_T1	66.22	3,354	2,622	78.2	0	0.0	3,354	2,622	78.2	0	0.0	0	6,241
SUM_T10	52.89	3,108	2,462	79.2	0	0.0	3,108	2,462	79.2	0	0.0	0	6,420
SUM_P	48.79	6,142	5,501	89.6	0	0.0	6,142	5,501	89.6	0	0.0	0	8,058
SUM_OP	41.90	6,092	5,620	92.3	0	0.0	6,092	5,620	92.3	0	0.0	0	8,531
WIN_T10	44.14	9,589	8,017	83.6	0	0.0	9,317	7,745	83.1	0	0.0	-77	6,964
WIN_P	42.83	12,693	11,138	87.8	0	0.0	12,501	10,946	87.6	0	0.0	-32	7,694
WIN_OP	41.26	12,287	10,748	87.5	91	0.7	12,207	10,668	87.4	91	0.7	-14	7,657

FPL/Vandolah

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	88	19	21.9	3	3.1	88	20	22.3	1	0.9	24	1,304
SF_P	89.98	187	27	14.4	8	4.2	187	27	14.6	6	3.4	2	3,156
SF_OP	63.28	91	26	29.0	9	9.6	91	27	29.8	7	7.8	16	1,519
SUM_T1	59.40	113	23	20.2	0	0.0	113	23	20.2	0	0.0	0	924
SUM_T10	46.95	112	15	13.5	0	0.0	112	15	13.5	0	0.0	0	1,133
SUM_P	38.76	112	18	16.2	0	0.0	112	18	16.2	0	0.0	0	1,401
SUM_OP	32.96	111	15	13.2	0	0.0	111	15	13.2	0	0.0	0	1,130
WIN_T10	84.57	174	20	11.5	1	0.6	174	20	11.3	1	0.6	-3	4,204
WIN_P	74.84	177	24	13.5	3	1.9	177	24	13.4	3	1.9	-2	4,284
WIN_OP	74.62	184	20	11.0	3	1.8	184	20	10.9	3	1.8	-1	4,458

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	411	98	23.9	0	0.0	411	97	23.6	0	0.0	-24	999
SF_P	41.32	349	226	64.6	0	0.0	349	223	63.9	0	0.0	-76	4,226
SF_OP	33.42	346	137	39.6	0	0.0	346	133	38.5	0	0.0	-69	1,961
SUM_T1	69.37	604	112	18.6	0	0.0	604	118	19.5	0	0.0	12	818
SUM_T10	58.61	604	143	23.7	0	0.0	604	143	23.7	0	0.0	0	971
SUM_P	52.76	578	189	32.6	0	0.0	578	189	32.6	0	0.0	0	1,423
SUM_OP	40.29	531	221	41.6	0	0.0	531	221	41.6	0	0.0	0	2,089
WIN_T10	64.53	224	58	25.7	0	0.0	224	57	25.3	0	0.0	-16	1,491
WIN_P	49.71	165	74	45.1	0	0.0	165	74	44.7	0	0.0	-36	2,285
WIN_OP	47.53	163	61	37.5	2	1.3	163	61	37.3	2	1.3	-10	1,849

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	41.51	145	0	0.0	0	0.0	145	0	0.0	0	0.0	0	4,941
SF_OP	40.10	269	0	0.0	0	0.0	269	0	0.0	0	0.0	0	8,400
SUM_T1	69.25	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	70.52	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	58.43	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	46.06	250	0	0.0	0	0.0	250	0	0.0	0	0.0	0	8,150
WIN_T10	44.14	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	54.97	619	0	0.0	0	0.0	619	0	0.0	0	0.0	0	8,973
WIN_OP	44.53	877	0	0.0	0	0.0	877	0	0.0	0	0.0	0	9,668

FPL/Vandolah

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	13,442	793	5.9	2	0.0	13,600	871	6.4	2	0.0	-6	579
SF_P	46.38	15,847	790	5.0	4	0.0	15,847	789	5.0	4	0.0	0	1,120
SF_OP	40.76	13,455	612	4.5	78	0.6	13,455	612	4.5	78	0.6	0	885
SUM_T1	82.29	13,320	1,045	7.8	68	0.5	13,322	1,078	8.1	46	0.3	3	634
SUM_T10	78.33	13,725	1,036	7.5	231	1.7	13,726	1,069	7.8	202	1.5	2	613
SUM_P	51.88	14,516	889	6.1	1	0.0	14,516	889	6.1	1	0.0	0	963
SUM_OP	48.40	14,446	709	4.9	83	0.6	14,446	742	5.1	17	0.1	2	1,267
WIN_T10	60.90	19,897	456	2.3	112	0.6	19,897	456	2.3	112	0.6	0	1,231
WIN_P	43.27	16,598	547	3.3	1	0.0	16,598	547	3.3	1	0.0	0	1,239
WIN_OP	40.94	15,177	412	2.7	171	1.1	15,177	412	2.7	171	1.1	0	1,027

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	279	22	7.8	21	7.5	279	22	7.9	18	6.5	-7	815
SF_P	56.38	307	35	11.5	26	8.6	307	36	11.8	23	7.6	-8	757
SF_OP	45.07	322	36	11.1	27	8.3	322	37	11.5	23	7.2	-6	1,057
SUM_T1	91.95	234	11	4.7	18	7.6	216	12	5.5	0	0.0	45	879
SUM_T10	77.26	234	12	4.9	18	7.6	216	12	5.8	0	0.0	47	911
SUM_P	59.86	219	12	5.5	18	8.4	202	13	6.6	0	0.0	18	760
SUM_OP	44.85	197	10	5.1	18	9.1	197	10	5.1	18	9.1	0	924
WIN_T10	66.31	401	51	12.6	0	0.0	401	50	12.4	0	0.0	-4	1,123
WIN_P	53.86	508	46	9.1	19	3.7	508	44	8.8	19	3.7	-2	1,691
WIN_OP	42.11	428	52	12.0	22	5.1	428	51	11.9	22	5.1	-2	1,466

Scenario: 2.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	2,174	214	9.8	0	0.0	2,174	292	13.4	0	0.0	18	2,022
SF_P	56.09	3,177	262	8.3	256	8.1	3,177	308	9.7	165	5.2	-10	3,741
SF_OP	42.17	2,375	265	11.2	289	12.2	2,375	320	13.5	179	7.5	-29	3,062
SUM_T1	86.41	2,817	515	18.3	0	0.0	2,818	587	20.8	0	0.0	57	1,693
SUM_T10	74.71	2,807	550	19.6	4	0.1	2,808	622	22.2	0	0.0	67	1,728
SUM_P	60.73	3,446	585	17.0	148	4.3	3,446	664	19.3	0	0.0	67	2,508
SUM_OP	43.09	2,677	602	22.5	0	0.0	2,677	602	22.5	0	0.0	0	2,078
WIN_T10	55.59	2,572	184	7.2	0	0.0	2,572	181	7.0	0	0.0	-1	5,092
WIN_P	52.58	3,099	265	8.6	5	0.2	3,099	265	8.6	5	0.2	0	6,606
WIN_OP	42.17	2,866	250	8.7	10	0.3	2,866	249	8.7	10	0.3	0	6,365

FPL/Vandolah

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	1,621	44	2.7	0	0.0	2,193	320	14.6	0	0.0	-331	1,235
SF_P	30.55	1,046	53	5.1	0	0.0	1,046	53	5.1	0	0.0	0	2,512
SF_OP	28.33	817	44	5.3	0	0.0	817	44	5.3	0	0.0	0	3,510
SUM_T1	56.09	1,432	0	0.0	0	0.0	2,024	297	14.7	0	0.0	-694	1,553
SUM_T10	49.74	1,432	0	0.0	0	0.0	2,024	297	14.7	0	0.0	-694	1,553
SUM_P	34.67	806	0	0.0	0	0.0	806	0	0.0	0	0.0	0	4,818
SUM_OP	29.40	557	0	0.0	0	0.0	557	0	0.0	0	0.0	0	8,611
WIN_T10	44.40	2,190	398	18.2	0	0.0	2,190	389	17.8	0	0.0	-10	1,309
WIN_P	31.21	1,096	72	6.5	0	0.0	1,096	72	6.5	0	0.0	0	2,273
WIN_OP	31.24	1,006	46	4.6	0	0.0	1,006	46	4.6	0	0.0	0	2,513

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	184	0	0.0	0	0.0	184	0	0.0	0	0.0	0	6,546
SF_P	43.61	519	317	61.1	0	0.0	519	317	61.1	0	0.0	0	4,563
SF_OP	29.75	476	317	66.7	0	0.0	476	317	66.7	0	0.0	0	5,375
SUM_T1	36.01	235	0	0.0	0	0.0	235	0	0.0	0	0.0	0	6,298
SUM_T10	66.19	240	0	0.0	0	0.0	240	0	0.0	0	0.0	0	6,037
SUM_P	46.99	222	0	0.0	0	0.0	222	0	0.0	0	0.0	0	6,744
SUM_OP	35.80	196	0	0.0	0	0.0	196	0	0.0	0	0.0	0	8,289
WIN_T10	38.56	206	19	9.1	0	0.0	187	0	0.0	0	0.0	1,316	8,063
WIN_P	47.53	820	358	43.6	0	0.0	820	358	43.6	0	0.0	0	2,894
WIN_OP	39.65	823	358	43.5	0	0.0	823	358	43.5	0	0.0	0	2,948

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	1,155	530	45.9	0	0.0	895	270	30.2	0	0.0	-890	1,675
SF_P	33.87	6,383	5,823	91.2	0	0.0	6,191	5,631	91.0	0	0.0	-49	8,288
SF_OP	30.71	6,312	5,807	92.0	0	0.0	6,236	5,731	91.9	0	0.0	-18	8,461
SUM_T1	54.18	3,221	2,502	77.7	0	0.0	3,221	2,502	77.7	0	0.0	0	6,173
SUM_T10	43.27	1,792	1,310	73.1	0	0.0	1,792	1,310	73.1	0	0.0	0	5,584
SUM_P	39.92	3,198	2,894	90.5	0	0.0	3,198	2,894	90.5	0	0.0	0	8,242
SUM_OP	34.28	4,258	3,959	93.0	0	0.0	4,258	3,959	93.0	0	0.0	0	8,675
WIN_T10	36.12	6,053	5,291	87.4	0	0.0	6,020	5,258	87.3	0	0.0	-12	7,666
WIN_P	35.05	10,358	9,580	92.5	0	0.0	10,166	9,388	92.3	0	0.0	-26	8,537
WIN_OP	33.76	10,064	9,348	92.9	0	0.0	9,984	9,268	92.8	0	0.0	-10	8,626

FPL/Vandolah

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	88	22	25.0	3	3.0	88	22	25.4	0	0.4	25	1,121
SF_P	73.62	187	29	15.8	8	4.5	187	30	16.0	7	3.6	3	3,154
SF_OP	51.78	92	35	38.7	10	10.4	92	36	39.8	7	7.8	43	1,851
SUM_T1	48.60	112	13	11.8	0	0.0	112	13	11.8	0	0.0	0	1,017
SUM_T10	38.41	112	18	16.4	0	0.0	112	18	16.4	0	0.0	0	1,591
SUM_P	31.72	112	19	16.8	0	0.0	112	19	16.8	0	0.0	0	1,486
SUM_OP	26.96	111	15	13.7	0	0.0	111	15	13.7	0	0.0	0	1,211
WIN_T10	69.19	65	25	38.9	0	0.0	65	25	38.3	0	0.0	-41	1,918
WIN_P	61.24	68	33	48.2	2	2.4	68	33	47.8	2	2.4	-34	2,492
WIN_OP	61.06	75	24	31.5	3	3.5	75	24	31.4	3	3.5	-6	1,672

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	411	104	25.4	0	0.0	411	99	24.1	0	0.0	-50	1,052
SF_P	33.80	347	55	15.8	0	0.0	347	55	15.8	0	0.0	0	1,431
SF_OP	27.34	345	46	13.2	0	0.0	345	46	13.2	0	0.0	0	1,331
SUM_T1	56.75	603	104	17.3	0	0.0	603	104	17.3	0	0.0	0	776
SUM_T10	47.95	535	50	9.3	0	0.0	535	50	9.3	0	0.0	0	914
SUM_P	43.16	533	151	28.3	0	0.0	533	151	28.3	0	0.0	0	1,333
SUM_OP	32.97	529	43	8.2	0	0.0	529	43	8.2	0	0.0	0	960
WIN_T10	52.79	176	72	40.8	0	0.0	176	71	40.2	0	0.0	-43	1,954
WIN_P	40.67	165	104	62.6	0	0.0	165	102	61.9	0	0.0	-84	4,051
WIN_OP	38.89	163	91	55.6	0	0.0	163	90	55.5	0	0.0	-19	3,278

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	57	0	0.0	0	0.0	57	0	0.0	0	0.0	0	4,940
SF_P	33.97	49	0	0.0	0	0.0	49	0	0.0	0	0.0	0	4,940
SF_OP	32.81	132	0	0.0	0	0.0	132	0	0.0	0	0.0	0	6,983
SUM_T1	56.66	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_T10	57.70	78	0	0.0	0	0.0	78	0	0.0	0	0.0	0	4,885
SUM_P	47.81	52	0	0.0	0	0.0	52	0	0.0	0	0.0	0	4,885
SUM_OP	37.68	25	0	0.0	0	0.0	25	0	0.0	0	0.0	0	4,885
WIN_T10	36.12	20	0	0.0	0	0.0	20	0	0.0	0	0.0	0	5,006
WIN_P	44.97	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	8,207
WIN_OP	36.43	342	0	0.0	0	0.0	342	0	0.0	0	0.0	0	9,165

FPL/Vandolah

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	11,947	796	6.7	2	0.0	11,947	791	6.6	2	0.0	0	571
SF_P	37.94	9,664	617	6.4	2	0.0	9,664	615	6.4	2	0.0	0	675
SF_OP	33.35	9,572	428	4.5	0	0.0	9,572	428	4.5	0	0.0	0	791
SUM_T1	67.33	12,836	1,052	8.2	1	0.0	12,837	1,085	8.5	1	0.0	3	662
SUM_T10	64.09	12,802	1,047	8.2	1	0.0	12,803	1,080	8.4	1	0.0	3	663
SUM_P	42.44	10,604	840	7.9	1	0.0	10,604	840	7.9	1	0.0	0	560
SUM_OP	39.60	10,529	718	6.8	0	0.0	10,529	718	6.8	0	0.0	0	620
WIN_T10	49.82	14,197	459	3.2	0	0.0	14,197	459	3.2	0	0.0	0	780
WIN_P	35.41	9,384	283	3.0	1	0.0	9,384	283	3.0	1	0.0	0	808
WIN_OP	33.50	8,067	218	2.7	0	0.0	8,067	216	2.7	0	0.0	0	861

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	261	15	5.6	0	0.0	261	15	5.6	0	0.0	-12	897
SF_P	46.13	289	12	4.2	0	0.1	289	12	4.2	0	0.1	0	797
SF_OP	36.87	228	4	1.6	0	0.0	228	4	1.6	0	0.0	0	867
SUM_T1	75.23	216	11	5.1	0	0.0	216	12	5.6	0	0.0	-9	924
SUM_T10	63.22	216	6	2.9	0	0.1	216	8	3.5	0	0.1	-13	904
SUM_P	48.98	202	5	2.6	0	0.1	202	5	2.6	0	0.1	0	852
SUM_OP	36.69	180	3	1.8	0	0.1	180	3	1.8	0	0.1	0	983
WIN_T10	54.25	401	40	9.9	0	0.0	401	37	9.2	0	0.0	-1	1,302
WIN_P	44.06	403	9	2.2	0	0.1	403	9	2.2	0	0.1	0	1,417
WIN_OP	34.45	279	5	1.8	0	0.1	279	5	1.8	0	0.1	0	1,980

Scenario: 2.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: AEC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	1,931	213	11.0	0	0.0	1,931	208	10.8	0	0.0	-3	2,235
SF_P	45.89	2,626	282	10.7	0	0.0	2,626	282	10.7	0	0.0	0	3,548
SF_OP	34.51	2,376	246	10.3	0	0.0	2,376	245	10.3	0	0.0	0	3,166
SUM_T1	70.69	2,747	514	18.7	0	0.0	2,747	587	21.4	0	0.0	59	1,620
SUM_T10	61.13	2,800	543	19.4	0	0.0	2,800	618	22.1	0	0.0	62	1,741
SUM_P	49.69	3,197	614	19.2	0	0.0	3,197	614	19.2	0	0.0	0	2,693
SUM_OP	35.25	1,044	50	4.8	0	0.0	1,044	50	4.8	0	0.0	0	2,608
WIN_T10	45.49	2,338	228	9.8	0	0.0	2,338	228	9.8	0	0.0	0	5,697
WIN_P	43.02	2,888	261	9.0	0	0.0	2,888	261	9.0	0	0.0	0	6,396
WIN_OP	34.51	540	263	48.7	0	0.0	540	262	48.5	0	0.0	-21	3,318

FPL/Vandolah

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	53.18	13,298	195	1.5	8,077	60.7	13,297	481	3.6	7,505	56.4	-488	3,607
SF_P	33.94	8,913	112	1.3	5,538	62.1	8,913	112	1.3	5,538	62.1	0	4,175
SF_OP	31.48	7,121	112	1.6	4,300	60.4	7,121	112	1.6	4,300	60.4	0	3,986
SUM_T1	62.32	14,675	114	0.8	9,486	64.6	14,675	411	2.8	8,895	60.6	-494	4,033
SUM_T10	55.27	14,084	114	0.8	8,897	63.2	14,084	411	2.9	8,306	59.0	-501	3,868
SUM_P	38.52	11,044	114	1.0	6,922	62.7	11,044	114	1.0	6,922	62.7	0	4,298
SUM_OP	32.67	6,335	114	1.8	3,586	56.6	6,335	114	1.8	3,586	56.6	0	3,671
WIN_T10	49.33	10,978	140	1.3	5,964	54.3	10,978	139	1.3	5,964	54.3	0	3,528
WIN_P	34.68	8,204	139	1.7	4,891	59.6	8,203	138	1.7	4,891	59.6	1	4,041
WIN_OP	34.71	9,198	146	1.6	5,050	54.9	9,198	146	1.6	5,050	54.9	0	3,564

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	51.78	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	48.45	2,666	24	0.9	1	0.0	2,666	24	0.9	1	0.0	0	5,022
SF_OP	33.06	1,812	24	1.3	0	0.0	1,812	24	1.3	0	0.0	0	4,817
SUM_T1	40.01	2,411	31	1.3	2	0.1	2,411	31	1.3	2	0.1	0	4,650
SUM_T10	73.55	3,492	31	0.9	2	0.0	3,492	31	0.9	2	0.0	0	4,728
SUM_P	52.21	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	39.78	2,424	31	1.3	0	0.0	2,424	31	1.3	0	0.0	0	4,992
WIN_T10	42.84	2,904	28	1.0	0	0.0	2,904	28	1.0	0	0.0	0	5,038
WIN_P	52.81	3,032	28	0.9	0	0.0	3,032	28	0.9	0	0.0	0	5,097
WIN_OP	44.06	2,861	28	1.0	0	0.0	2,861	28	1.0	0	0.0	0	5,022

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	43.88	30,951	28,608	92.4	494	1.6	30,691	28,348	92.4	494	1.6	-12	8,543
SF_P	37.63	29,246	27,059	92.5	306	1.0	29,054	26,867	92.5	306	1.1	-9	8,564
SF_OP	34.12	25,065	22,913	91.4	490	2.0	24,989	22,837	91.4	490	2.0	-5	8,368
SUM_T1	60.20	35,433	33,870	95.6	0	0.0	35,433	33,870	95.6	0	0.0	0	9,143
SUM_T10	48.08	33,932	32,455	95.6	0	0.0	33,932	32,455	95.6	0	0.0	0	9,155
SUM_P	44.35	30,793	29,333	95.3	0	0.0	30,793	29,333	95.3	0	0.0	0	9,081
SUM_OP	38.09	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	40.13	30,943	28,595	92.4	247	0.8	30,671	28,323	92.3	247	0.8	-12	8,539
WIN_P	38.94	28,801	26,664	92.6	132	0.5	28,609	26,472	92.5	132	0.5	-9	8,575
WIN_OP	37.51	26,267	24,124	91.8	345	1.3	26,187	24,044	91.8	345	1.3	-4	8,445

FPL/Vandolah

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	220.20	546	26	4.8	8	1.4	545	26	4.8	7	1.3	4	5,181
SF_P	81.80	363	27	7.5	8	2.2	362	27	7.5	8	2.1	3	3,621
SF_OP	57.53	267	27	10.2	8	3.0	267	28	10.3	7	2.8	2	2,610
SUM_T1	54.00	526	44	8.4	11	2.1	526	44	8.4	11	2.1	0	4,213
SUM_T10	42.68	308	57	18.4	5	1.8	308	57	18.4	5	1.8	0	2,489
SUM_P	35.24	302	64	21.0	3	1.1	302	64	21.0	3	1.1	0	2,619
SUM_OP	29.96	199	30	14.9	0	0.0	199	30	14.9	0	0.0	0	2,984
WIN_T10	76.88	377	20	5.3	5	1.2	377	20	5.2	5	1.2	4	4,227
WIN_P	68.04	268	22	8.1	5	1.7	268	22	8.0	5	1.7	2	3,115
WIN_OP	67.84	268	19	7.2	5	1.8	268	19	7.2	5	1.8	1	3,117

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	61.51	2,558	108	4.2	25	1.0	2,557	108	4.2	25	1.0	5	7,122
SF_P	37.56	1,009	166	16.4	4	0.4	1,007	164	16.3	4	0.4	10	4,737
SF_OP	30.38	841	103	12.2	0	0.0	840	102	12.1	0	0.0	7	4,052
SUM_T1	63.06	2,876	168	5.8	38	1.3	2,876	168	5.8	38	1.3	0	6,356
SUM_T10	53.28	2,169	178	8.2	29	1.3	2,169	178	8.2	29	1.3	0	5,540
SUM_P	47.96	1,857	188	10.1	18	0.9	1,857	188	10.1	18	0.9	0	5,333
SUM_OP	36.63	1,052	184	17.4	0	0.0	1,052	184	17.4	0	0.0	0	3,251
WIN_T10	58.66	1,911	47	2.5	8	0.4	1,911	47	2.5	8	0.4	4	7,846
WIN_P	45.19	1,168	60	5.2	2	0.1	1,168	60	5.1	2	0.1	5	7,468
WIN_OP	43.21	1,002	50	5.0	10	1.0	1,002	50	5.0	10	1.0	2	7,114

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.38	2,626	0	0.0	0	0.0	2,626	0	0.0	0	0.0	0	9,451
SF_P	37.74	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	36.45	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	62.95	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	64.11	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	53.12	2,619	0	0.0	0	0.0	2,619	0	0.0	0	0.0	0	9,480
SUM_OP	41.87	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	40.13	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	49.97	2,487	0	0.0	0	0.0	2,487	0	0.0	0	0.0	0	9,663
WIN_OP	40.48	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.16	47,746	652	1.4	1,761	3.7	47,743	650	1.4	1,761	3.7	0	4,014
SF_P	42.16	42,006	602	1.4	1,737	4.1	42,004	600	1.4	1,737	4.1	0	3,871
SF_OP	37.05	35,446	428	1.2	1,789	5.0	35,446	427	1.2	1,789	5.0	0	4,007
SUM_T1	74.81	55,390	901	1.6	1,092	2.0	55,390	910	1.6	1,072	1.9	0	4,393
SUM_T10	71.21	55,090	884	1.6	1,094	2.0	55,090	894	1.6	1,074	2.0	0	4,414
SUM_P	47.16	46,884	724	1.5	1,027	2.2	46,884	724	1.5	1,027	2.2	0	4,362
SUM_OP	44.00	43,583	577	1.3	958	2.2	43,583	577	1.3	958	2.2	0	4,365
WIN_T10	55.36	52,967	325	0.6	1,944	3.7	52,966	324	0.6	1,944	3.7	0	4,074
WIN_P	39.34	41,977	359	0.9	1,678	4.0	41,976	358	0.9	1,678	4.0	0	4,055
WIN_OP	37.22	38,073	221	0.6	1,884	4.9	38,072	220	0.6	1,884	4.9	0	4,014

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.45	883	36	4.1	41	4.7	882	36	4.1	41	4.6	3	5,242
SF_P	51.25	873	42	4.8	45	5.2	873	41	4.7	45	5.2	4	5,350
SF_OP	40.97	760	40	5.3	43	5.6	760	40	5.3	42	5.6	2	5,296
SUM_T1	83.59	916	10	1.1	34	3.7	916	10	1.1	33	3.6	0	6,011
SUM_T10	70.24	916	10	1.1	34	3.7	916	10	1.1	34	3.7	0	6,018
SUM_P	54.42	896	10	1.2	30	3.4	896	10	1.2	30	3.4	0	6,231
SUM_OP	40.77	699	10	1.4	31	4.4	699	10	1.4	31	4.4	0	5,853
WIN_T10	60.28	1,048	43	4.1	46	4.4	1,048	42	4.1	46	4.4	4	5,445
WIN_P	48.96	1,036	23	2.3	51	4.9	1,036	23	2.2	51	4.9	6	5,607
WIN_OP	38.28	816	23	2.8	46	5.6	815	23	2.8	46	5.6	3	5,111

Scenario: 1.0 Alternate Case Mitigation Case
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	60.79	6,929	240	3.5	781	11.3	6,927	248	3.6	760	11.0	-3	5,587
SF_P	50.99	6,396	241	3.8	792	12.4	6,395	240	3.7	792	12.4	3	5,447
SF_OP	38.34	5,587	242	4.3	784	14.0	5,586	241	4.3	784	14.0	1	5,242
SUM_T1	78.55	8,461	622	7.3	829	9.8	8,461	629	7.4	814	9.6	-2	5,148
SUM_T10	67.92	8,163	621	7.6	824	10.1	8,163	630	7.7	807	9.9	-3	5,007
SUM_P	55.21	7,602	624	8.2	840	11.1	7,602	624	8.2	840	11.1	0	5,023
SUM_OP	39.17	6,546	627	9.6	815	12.5	6,546	627	9.6	815	12.5	0	4,513
WIN_T10	50.54	6,237	161	2.6	568	9.1	6,235	159	2.6	568	9.1	3	6,794
WIN_P	47.80	6,326	201	3.2	578	9.1	6,324	200	3.2	578	9.1	3	6,840
WIN_OP	38.34	5,784	174	3.0	566	9.8	5,784	174	3.0	566	9.8	1	6,582

FPL/Vandolah

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	58.50	13,858	190	1.4	8,635	62.3	13,858	476	3.4	8,064	58.2	-482	3,774
SF_P	37.33	10,902	112	1.0	6,592	60.5	10,902	112	1.0	6,592	60.5	0	4,094
SF_OP	34.63	10,716	112	1.0	6,246	58.3	10,716	256	2.4	6,103	57.0	-149	3,790
SUM_T1	68.55	14,810	114	0.8	9,622	65.0	14,810	411	2.8	9,030	61.0	-492	4,071
SUM_T10	60.80	14,558	114	0.8	9,369	64.4	14,558	411	2.8	8,778	60.3	-495	4,001
SUM_P	42.37	11,327	114	1.0	6,922	61.1	11,327	114	1.0	6,922	61.1	0	4,153
SUM_OP	35.94	9,461	114	1.2	5,191	54.9	9,461	114	1.2	5,191	54.9	0	3,593
WIN_T10	54.26	11,350	140	1.2	6,345	55.9	11,350	140	1.2	6,345	55.9	0	3,662
WIN_P	38.15	9,444	141	1.5	5,416	57.3	9,444	141	1.5	5,416	57.4	0	3,760
WIN_OP	38.18	9,720	143	1.5	5,050	52.0	9,720	143	1.5	5,050	52.0	0	3,421

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	56.96	2,679	24	0.9	1	0.0	2,679	24	0.9	1	0.0	0	4,997
SF_P	53.30	2,745	24	0.9	1	0.0	2,745	24	0.9	1	0.0	0	4,939
SF_OP	36.37	2,015	24	1.2	0	0.0	2,015	24	1.2	0	0.0	0	5,124
SUM_T1	44.01	2,416	31	1.3	2	0.1	2,416	31	1.3	2	0.1	0	4,631
SUM_T10	80.91	3,507	31	0.9	2	0.0	3,507	31	0.9	2	0.0	0	4,740
SUM_P	57.43	3,225	31	1.0	1	0.0	3,225	31	1.0	1	0.0	0	4,904
SUM_OP	43.76	2,623	31	1.2	0	0.0	2,623	31	1.2	0	0.0	0	5,244
WIN_T10	47.12	3,008	28	0.9	0	0.0	3,008	28	0.9	0	0.0	0	5,143
WIN_P	58.09	3,124	28	0.9	0	0.0	3,124	28	0.9	0	0.0	0	5,005
WIN_OP	48.47	2,998	28	0.9	0	0.0	2,998	28	0.9	0	0.0	0	5,161

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.27	31,999	29,493	92.2	626	2.0	31,739	29,233	92.1	626	2.0	-12	8,496
SF_P	41.39	30,664	28,166	91.9	483	1.6	30,472	27,974	91.8	483	1.6	-9	8,440
SF_OP	37.53	25,672	23,490	91.5	590	2.3	25,596	23,414	91.5	590	2.3	-5	8,384
SUM_T1	66.22	35,433	33,870	95.6	0	0.0	35,433	33,870	95.6	0	0.0	0	9,143
SUM_T10	52.89	33,932	32,455	95.6	0	0.0	33,932	32,455	95.6	0	0.0	0	9,155
SUM_P	48.79	31,163	29,703	95.3	0	0.0	31,163	29,703	95.3	0	0.0	0	9,092
SUM_OP	41.90	27,370	26,092	95.3	0	0.0	27,370	26,092	95.3	0	0.0	0	9,096
WIN_T10	44.14	31,315	28,806	92.0	348	1.1	31,043	28,534	91.9	348	1.1	-13	8,461
WIN_P	42.83	30,575	28,240	92.4	300	1.0	30,383	28,048	92.3	300	1.0	-9	8,533
WIN_OP	41.26	28,028	25,727	91.8	270	1.0	27,948	25,647	91.8	270	1.0	-4	8,434

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	242.22	546	26	4.7	7	1.4	545	26	4.7	7	1.3	4	5,181
SF_P	89.98	363	27	7.3	8	2.2	362	27	7.4	8	2.1	3	3,622
SF_OP	63.28	267	26	9.8	8	3.1	267	26	9.9	8	2.9	2	2,601
SUM_T1	59.40	530	40	7.6	9	1.7	530	40	7.6	9	1.7	0	4,229
SUM_T10	46.95	526	56	10.6	8	1.6	526	56	10.6	8	1.6	0	4,211
SUM_P	38.76	305	67	22.1	2	0.7	305	67	22.1	2	0.7	0	2,629
SUM_OP	32.96	200	42	21.1	0	0.0	200	42	21.1	0	0.0	0	3,004
WIN_T10	84.57	377	19	5.1	4	1.2	377	19	5.1	4	1.2	3	4,228
WIN_P	74.84	378	21	5.5	5	1.3	378	20	5.4	5	1.3	3	4,222
WIN_OP	74.62	377	19	5.0	5	1.2	377	19	5.0	5	1.2	1	4,229

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	67.66	2,558	105	4.1	27	1.0	2,557	105	4.1	25	1.0	5	7,120
SF_P	41.32	1,168	150	12.8	6	0.5	1,167	149	12.7	6	0.5	7	5,246
SF_OP	33.42	847	143	16.9	0	0.0	847	142	16.8	0	0.0	3	4,060
SUM_T1	69.37	2,876	163	5.7	41	1.4	2,876	165	5.7	38	1.3	0	6,354
SUM_T10	58.61	2,878	174	6.0	40	1.4	2,878	174	6.0	40	1.4	0	6,352
SUM_P	52.76	2,163	177	8.2	34	1.6	2,163	177	8.2	34	1.6	0	5,546
SUM_OP	40.29	1,213	185	15.3	16	1.3	1,213	185	15.3	16	1.3	0	3,708
WIN_T10	64.53	1,911	47	2.4	8	0.4	1,911	46	2.4	8	0.4	3	7,845
WIN_P	49.71	1,489	54	3.6	5	0.3	1,488	53	3.6	5	0.3	4	7,964
WIN_OP	47.53	1,484	48	3.3	9	0.6	1,484	48	3.2	9	0.6	2	7,980

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	62.02	2,762	0	0.0	0	0.0	2,762	0	0.0	0	0.0	0	9,477
SF_P	41.51	2,211	0	0.0	0	0.0	2,211	0	0.0	0	0.0	0	9,440
SF_OP	40.10	2,175	0	0.0	0	0.0	2,175	0	0.0	0	0.0	0	9,730
SUM_T1	69.25	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_T10	70.52	3,115	0	0.0	0	0.0	3,115	0	0.0	0	0.0	0	9,351
SUM_P	58.43	2,895	0	0.0	0	0.0	2,895	0	0.0	0	0.0	0	9,529
SUM_OP	46.06	2,685	0	0.0	0	0.0	2,685	0	0.0	0	0.0	0	9,755
WIN_T10	44.14	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	54.97	2,630	0	0.0	0	0.0	2,630	0	0.0	0	0.0	0	9,681
WIN_OP	44.53	2,729	0	0.0	0	0.0	2,729	0	0.0	0	0.0	0	9,862

FPL/Vandolah

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.58	48,203	650	1.3	1,821	3.8	48,200	673	1.4	1,770	3.7	0	3,965
SF_P	46.38	44,226	602	1.4	1,706	3.9	44,224	600	1.4	1,706	3.9	0	4,001
SF_OP	40.76	39,197	446	1.1	1,710	4.4	39,196	445	1.1	1,710	4.4	0	3,837
SUM_T1	82.29	55,621	901	1.6	1,077	1.9	55,621	910	1.6	1,058	1.9	0	4,364
SUM_T10	78.33	55,548	884	1.6	1,085	2.0	55,548	894	1.6	1,066	1.9	0	4,375
SUM_P	51.88	48,601	723	1.5	968	2.0	48,601	723	1.5	968	2.0	0	4,446
SUM_OP	48.40	45,319	574	1.3	949	2.1	45,319	588	1.3	921	2.0	0	4,501
WIN_T10	60.90	54,692	325	0.6	1,852	3.4	54,691	324	0.6	1,852	3.4	0	4,220
WIN_P	43.27	46,754	353	0.8	1,866	4.0	46,753	353	0.8	1,866	4.0	0	3,928
WIN_OP	40.94	42,454	314	0.7	1,899	4.5	42,453	314	0.7	1,899	4.5	0	3,919

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	73.10	884	35	4.0	43	4.9	884	35	4.0	42	4.8	3	5,223
SF_P	56.38	880	39	4.4	41	4.7	880	39	4.4	40	4.6	3	5,261
SF_OP	45.07	846	38	4.6	40	4.8	846	39	4.6	39	4.6	1	5,614
SUM_T1	91.95	916	10	1.1	33	3.6	916	10	1.1	33	3.6	0	6,009
SUM_T10	77.26	916	10	1.1	34	3.7	916	10	1.1	33	3.6	0	6,017
SUM_P	59.86	897	10	1.1	30	3.4	897	10	1.2	29	3.3	0	6,216
SUM_OP	44.85	785	10	1.3	29	3.7	785	10	1.3	29	3.7	0	6,183
WIN_T10	66.31	1,048	42	4.0	46	4.4	1,047	42	4.0	46	4.4	4	5,445
WIN_P	53.86	1,049	47	4.5	51	4.9	1,049	46	4.4	51	4.9	4	5,471
WIN_OP	42.11	935	47	5.0	50	5.3	935	46	5.0	50	5.3	2	5,387

Scenario: 1.1 Alternate Case Mitigation Case, Price +10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	66.87	6,935	239	3.4	777	11.2	6,933	247	3.6	757	10.9	-2	5,575
SF_P	56.09	6,771	240	3.5	779	11.5	6,770	249	3.7	757	11.2	-4	5,562
SF_OP	42.17	5,588	241	4.3	805	14.4	5,587	254	4.5	778	13.9	-10	5,233
SUM_T1	86.41	8,461	621	7.3	830	9.8	8,461	629	7.4	814	9.6	-2	5,148
SUM_T10	74.71	8,161	621	7.6	829	10.2	8,161	629	7.7	813	10.0	-2	5,010
SUM_P	60.73	7,811	621	8.0	830	10.6	7,811	631	8.1	811	10.4	-3	4,849
SUM_OP	43.09	6,549	626	9.6	832	12.7	6,549	626	9.6	832	12.7	0	4,512
WIN_T10	55.59	6,472	134	2.1	565	8.7	6,471	132	2.0	565	8.7	2	6,456
WIN_P	52.58	6,326	164	2.6	570	9.0	6,325	163	2.6	570	9.0	2	6,833
WIN_OP	42.17	5,785	142	2.4	568	9.8	5,785	141	2.4	568	9.8	1	6,578

FPL/Vandolah

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Duke Energy Florida

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	47.86	12,944	194	1.5	7,723	59.7	12,944	480	3.7	7,152	55.3	-491	3,497
SF_P	30.55	6,486	112	1.7	4,789	73.8	6,486	112	1.7	4,789	73.8	0	5,560
SF_OP	28.33	3,706	112	3.0	1,466	39.6	3,706	112	3.0	1,466	39.6	0	2,624
SUM_T1	56.09	14,049	114	0.8	8,862	63.1	14,049	411	2.9	8,270	58.9	-501	3,858
SUM_T10	49.74	13,611	114	0.8	8,424	61.9	13,611	411	3.0	7,833	57.5	-506	3,730
SUM_P	34.67	7,869	114	1.5	5,033	64.0	7,869	114	1.5	5,033	64.0	0	4,410
SUM_OP	29.40	2,895	114	4.0	1,511	52.2	2,895	114	4.0	1,511	52.2	0	3,233
WIN_T10	44.40	10,624	140	1.3	5,610	52.8	10,623	140	1.3	5,610	52.8	0	3,404
WIN_P	31.21	4,796	141	2.9	2,868	59.8	4,795	140	2.9	2,868	59.8	1	3,931
WIN_OP	31.24	5,502	135	2.5	2,502	45.5	5,502	135	2.5	2,502	45.5	0	3,098

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Florida Municipal Power Pool

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	46.60	2,589	24	0.9	1	0.0	2,589	24	0.9	1	0.0	0	4,896
SF_P	43.61	2,577	24	0.9	1	0.0	2,577	24	0.9	1	0.0	0	4,920
SF_OP	29.75	1,534	24	1.6	0	0.0	1,534	24	1.6	0	0.0	0	4,318
SUM_T1	36.01	2,299	31	1.3	2	0.1	2,299	31	1.3	2	0.1	0	4,502
SUM_T10	66.19	3,464	31	0.9	2	0.0	3,464	31	0.9	2	0.0	0	4,706
SUM_P	46.99	3,118	31	1.0	1	0.0	3,118	31	1.0	1	0.0	0	4,806
SUM_OP	35.80	2,196	31	1.4	0	0.0	2,196	31	1.4	0	0.0	0	4,711
WIN_T10	38.56	2,558	28	1.1	0	0.0	2,558	28	1.1	0	0.0	0	4,673
WIN_P	47.53	2,928	28	0.9	0	0.0	2,928	28	0.9	0	0.0	0	4,992
WIN_OP	39.65	2,658	28	1.0	0	0.0	2,658	28	1.0	0	0.0	0	4,808

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Florida Power & Light

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	39.49	29,244	27,078	92.6	382	1.3	28,984	26,818	92.5	382	1.3	-12	8,574
SF_P	33.87	28,068	25,910	92.3	338	1.2	27,876	25,718	92.3	338	1.2	-10	8,525
SF_OP	30.71	24,812	22,886	92.2	0	0.0	24,736	22,810	92.2	0	0.0	-4	8,520
SUM_T1	54.18	35,300	33,750	95.6	0	0.0	35,300	33,750	95.6	0	0.0	0	9,147
SUM_T10	43.27	32,615	31,303	96.0	0	0.0	32,615	31,303	96.0	0	0.0	0	9,217
SUM_P	39.92	28,219	27,096	96.0	0	0.0	28,219	27,096	96.0	0	0.0	0	9,228
SUM_OP	34.28	25,536	24,431	95.7	0	0.0	25,536	24,431	95.7	0	0.0	0	9,162
WIN_T10	36.12	28,424	26,305	92.5	23	0.1	28,152	26,033	92.5	23	0.1	-13	8,565
WIN_P	35.05	28,789	26,667	92.6	114	0.4	28,597	26,475	92.6	114	0.4	-9	8,584
WIN_OP	33.76	26,252	24,124	91.9	21	0.1	26,172	24,044	91.9	21	0.1	-4	8,456

FPL/Vandolah

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Gainesville Regional Utilities

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	198.18	546	26	4.8	8	1.4	545	26	4.8	7	1.3	4	5,180
SF_P	73.62	363	28	7.6	8	2.3	362	28	7.6	8	2.1	3	3,622
SF_OP	51.78	267	30	11.0	9	3.2	267	30	11.1	8	3.0	2	2,611
SUM_T1	48.60	526	54	10.3	9	1.7	526	54	10.3	9	1.7	0	4,211
SUM_T10	38.41	306	55	18.0	4	1.3	306	55	18.0	4	1.3	0	2,497
SUM_P	31.72	198	64	32.2	3	1.7	198	64	32.2	3	1.7	0	3,276
SUM_OP	26.96	196	52	26.3	0	0.0	196	52	26.3	0	0.0	0	3,097
WIN_T10	69.19	268	21	7.7	4	1.7	268	21	7.7	4	1.7	3	3,118
WIN_P	61.24	269	23	8.7	5	1.7	269	23	8.7	5	1.7	3	3,119
WIN_OP	61.06	268	20	7.5	4	1.7	268	20	7.5	4	1.7	1	3,120

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: JEA

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	55.36	2,076	114	5.5	26	1.3	2,075	113	5.5	26	1.3	6	6,531
SF_P	33.80	848	110	12.9	6	0.7	846	107	12.7	6	0.7	15	4,021
SF_OP	27.34	334	97	29.0	0	0.0	332	96	28.8	0	0.0	-2	2,582
SUM_T1	56.75	2,878	176	6.1	36	1.3	2,878	176	6.1	36	1.3	0	6,353
SUM_T10	47.95	1,544	197	12.8	10	0.6	1,544	197	12.8	10	0.6	0	4,626
SUM_P	43.16	1,378	204	14.8	4	0.3	1,378	204	14.8	4	0.3	0	4,240
SUM_OP	32.97	1,046	153	14.6	0	0.0	1,046	153	14.6	0	0.0	0	3,250
WIN_T10	52.79	1,864	50	2.7	9	0.5	1,864	49	2.7	9	0.5	4	8,239
WIN_P	40.67	845	68	8.1	1	0.1	844	68	8.0	1	0.1	8	6,651
WIN_OP	38.89	841	56	6.7	5	0.5	840	56	6.7	5	0.5	3	6,648

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Seminole Electric Cooperative

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	50.74	2,354	0	0.0	0	0.0	2,354	0	0.0	0	0.0	0	9,388
SF_P	33.97	2,115	0	0.0	0	0.0	2,115	0	0.0	0	0.0	0	9,415
SF_OP	32.81	2,039	0	0.0	0	0.0	2,039	0	0.0	0	0.0	0	9,713
SUM_T1	56.66	2,701	0	0.0	0	0.0	2,701	0	0.0	0	0.0	0	9,254
SUM_T10	57.70	2,977	0	0.0	0	0.0	2,977	0	0.0	0	0.0	0	9,322
SUM_P	47.81	2,496	0	0.0	0	0.0	2,496	0	0.0	0	0.0	0	9,455
SUM_OP	37.68	2,311	0	0.0	0	0.0	2,311	0	0.0	0	0.0	0	9,716
WIN_T10	36.12	2,208	0	0.0	0	0.0	2,208	0	0.0	0	0.0	0	9,771
WIN_P	44.97	2,353	0	0.0	0	0.0	2,353	0	0.0	0	0.0	0	9,644
WIN_OP	36.43	2,194	0	0.0	0	0.0	2,194	0	0.0	0	0.0	0	9,829

FPL/Vandolah

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Southern Company

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	48.74	45,893	654	1.4	1,771	3.9	45,890	652	1.4	1,771	3.9	0	3,951
SF_P	37.94	37,710	610	1.6	1,786	4.7	37,707	607	1.6	1,786	4.7	0	3,900
SF_OP	33.35	35,280	431	1.2	1,813	5.1	35,279	430	1.2	1,813	5.1	0	4,008
SUM_T1	67.33	53,910	901	1.7	1,057	2.0	53,910	911	1.7	1,037	1.9	0	4,343
SUM_T10	64.09	52,990	885	1.7	1,055	2.0	52,990	895	1.7	1,034	2.0	0	4,296
SUM_P	42.44	44,530	722	1.6	1,164	2.6	44,530	722	1.6	1,164	2.6	0	4,329
SUM_OP	39.60	40,743	577	1.4	1,095	2.7	40,743	577	1.4	1,095	2.7	0	4,354
WIN_T10	49.82	50,334	327	0.6	1,940	3.9	50,333	326	0.6	1,940	3.9	0	3,996
WIN_P	35.41	39,070	363	0.9	1,672	4.3	39,067	360	0.9	1,672	4.3	1	3,906
WIN_OP	33.50	35,584	225	0.6	1,573	4.4	35,584	224	0.6	1,573	4.4	0	4,028

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Tallahassee FL (City of)

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	59.81	882	38	4.3	42	4.7	882	38	4.3	41	4.6	3	5,251
SF_P	46.13	870	22	2.5	49	5.6	870	22	2.5	49	5.6	6	5,392
SF_OP	36.87	677	23	3.4	48	7.1	676	23	3.4	48	7.1	3	5,017
SUM_T1	75.23	916	10	1.1	34	3.7	916	10	1.1	34	3.7	0	6,018
SUM_T10	63.22	913	10	1.1	32	3.4	913	11	1.2	31	3.4	0	6,049
SUM_P	48.98	888	10	1.2	33	3.8	888	10	1.2	33	3.8	0	6,353
SUM_OP	36.69	459	10	2.2	30	6.6	459	10	2.2	30	6.6	0	4,443
WIN_T10	54.25	1,042	44	4.3	52	5.0	1,041	44	4.2	52	5.0	5	5,518
WIN_P	44.06	960	29	3.0	52	5.4	960	28	2.9	52	5.4	7	5,188
WIN_OP	34.45	571	25	4.4	50	8.7	571	25	4.4	50	8.7	4	3,589

Scenario: 1.2 Alternate Case Mitigation Case, Price -10%
Capacity Type: EC

Destination: Tampa Electric Co

Period	Price ($/MWh)	Pre Market Size	NEE Pre Cap. (MW)	NEE Pre Share (%)	DUK Pre Cap. (MW)	DUK Pre Share (%)	Post Market Size	NEE Post Cap. (MW)	NEE Post Share (%)	DUK Post Cap. (MW)	DUK Post Share (%)	HHI Change	Post HHI
SF_T10	54.71	6,692	241	3.6	801	12.0	6,690	239	3.6	801	12.0	4	5,880
SF_P	45.89	6,219	243	3.9	793	12.7	6,217	242	3.9	793	12.7	3	5,634
SF_OP	34.51	5,585	241	4.3	759	13.6	5,584	240	4.3	759	13.6	2	5,258
SUM_T1	70.69	8,392	622	7.4	820	9.8	8,392	630	7.5	804	9.6	-2	5,113
SUM_T10	61.13	8,156	623	7.6	835	10.2	8,156	632	7.8	816	10.0	-3	5,019
SUM_P	49.69	7,559	629	8.3	839	11.1	7,559	629	8.3	839	11.1	0	5,082
SUM_OP	35.25	4,493	632	14.1	748	16.6	4,493	632	14.1	748	16.6	0	3,430
WIN_T10	45.49	6,236	197	3.2	576	9.2	6,234	195	3.1	576	9.2	4	6,801
WIN_P	43.02	6,113	219	3.6	557	9.1	6,112	218	3.6	557	9.1	3	6,747
WIN_OP	34.51	3,454	211	6.1	557	16.1	3,454	210	6.1	557	16.1	3	5,746

Non-affiliate Energy Sales in FPL BAA based on EQR Data, 2023-2024

Holding Company	Pre-transaction Sales (MWh)	Pre-transaction Sales Share based on MWh (%)	Post-transaction Sales (MWh)	Post-transaction Sales Share based on MWh (%)	Pre-transaction Sales ($)	Pre-transaction Sales Share based on $ (%)	Post-transaction Sales ($)	Post-transaction Sales Share based on $ (%)
NextEra Energy Inc	741,034	22.9	742357.0	22.9	22,468,388	17	22555392.0	16.8
Duke Energy Corp	1,323	0.0			87,004	0		
Energy Authority Inc (The)	1,016,317	31.4	1016317.0	31.4	34,733,808	26	34733808.0	25.9
United Energy Corp	612,180	18.9	612180.0	18.9	30,798,789	23	30798789.0	22.9
Macquarie Bank Limited	343,240	10.6	343240.0	10.6	20,340,328	15	20340328.0	15.2
General Electric Co	238,109	7.4	238109.0	7.4	15,049,362	11	15049362.0	11.2
Southern Co	124,604	3.8	124604.0	3.8	6,322,897	5	6322896.5	4.7
Florida Crystals Corp	91,929	2.8	91928.9	2.8	1,708,937	1	1708937.2	1.3
ITOCHU Corp	37,094	1.1	37094.0	1.1	1,193,172	1	1193172.0	0.9
TECO Energy Inc	19,866	0.6	19866.0	0.6	980,714	1	980714.0	0.7
Florida Municipal Power Agency	10,480	0.3	10480.0	0.3	339,924	0	339923.7	0.3
Seminole Electric Coop Inc	2,340	0.1	2340.0	0.1	146,354	0	146354.0	0.1
Municipal Electric Authority of Georgia	526	0.0	526.0	0.0	28,150	0	28150.0	0.0
Oglethorpe Power Corp	80	0.0	80.0	0.0	2,140	0	2140.0	0.0
Total	**3,239,122**	**100**	**3,239,122**	**100**	**134,199,966**	**100**	**134,199,966**	**100**
Pre-transaction HHI	2,056				1,858			
Post-transaction HHI	2,058				1,860			
HHI Change	2				2			

Source: Hitachi Energy via Velocity Suite Intelligent Query, EQR Transactions Data

Note: Assumes that NextEra Energy Inc is acquiring all of Duke Energy Corp within FPL

EIA 923 Generation in FPL by Company, 2023-2024

Holding Company	Pre-transaction Net Generation (MWh)	Pre-transaction Share based on MWh (%)	Post-transaction Net Generation (MWh)	Post-transaction Share based on MWh (%)
NextEra Energy Inc	271,587,086	98.0	273,025,069	98.0
Duke Energy Corp	292,450	0.1	292,450	0.1
Solid Waste Authority of Palm Beach	1,698,972	0.6	1,698,972	0.6
Rock Tenn Co	1,125,878	0.4	1,125,878	0.4
Macquarie Bank Limited	863,739	0.3	863,739	0.3
United States Sugar Corp	541,265	0.2	541,265	0.2
Koch Industries Inc	320,342	0.1	320,342	0.1
Plummer Forest Products Inc	192,334	0.1	192,334	0.1
PepsiCo Inc	188,110	0.1	188,110	0.1
Chesapeake Utilities Corp	172,330	0.1	172,330	0.1
Florida Crystals Corp	86,663	0.0	86,663	0.0
Waste Management Inc	64,476	0.0	64,476	0.0
Miami Dade Water & Sewer Authority	42,636	0.0	42,636	0.0
BP plc	27,789	0.0	27,789	0.0
Metro Dade County	25,506	0.0	25,506	0.0
Ikea Systems BV	1,393	0.0	1,393	0.0
Lime Energy	1,344	0.0	1,344	0.0
Pembroke Lakes Mall	596	0.0	596	0.0
Lake Worth Utilities	444	0.0	444	0.0
Florida Keys Electric Coop Association Inc	0	0.0	0	0.0
Manatee Green Power LLC	0	0.0	0	0.0
Total	**277,233,353**	**100.0**	**278,671,336**	**100.0**
Pre-transaction HHI	9,598			
Post-transaction HHI	9,600			
HHI Change	2			

Source: Hitachi Energy via Velocity Suite Intelligent Query,
EIA 923 Monthly Plant Generation & Consumption; Unit Generation and Emissions

EIA 923 Generation in DEF by Company, 2023-2024

Holding Company	Pre-transaction Net Generation (MWh)	Pre-transaction Share based on MWh (%)	Post-transaction Net Generation (MWh)	Post-transaction Share based on MWh (%)
NextEra Energy Inc	9,820	0.0	9,820	0.0
Duke Energy Corp	78,411,502	93.4	76,973,519	93.2
Florida Municipal Power Agency	1,718,781	2.0	1,718,781	2.1
UBS AG	1,630,180	1.9	1,630,180	2.0
Covanta Holding Corp	967,337	1.2	967,337	1.2
General Electric Co	541,093	0.6	541,093	0.7
Pasco (County Of)	368,941	0.4	368,941	0.4
Potash Corp of Saskatchewan Inc	156,203	0.2	156,203	0.2
Floridas Natural Growers	40,825	0.0	40,825	0.0
CB&I Inc	40,611	0.0	40,611	0.0
Sucocitrico Cutrale	24,466	0.0	24,466	0.0
GenOn Energy Inc	21,515	0.0	21,515	0.0
Renew Solar LLC	12,725	0.0	12,725	0.0
Storey Bend Solar LLC	10,682	0.0	10,682	0.0
BP plc	9,658	0.0	9,658	0.0
Brookfield Asset Management Inc	8,748	0.0	8,748	0.0
Nick King	8,740	0.0	8,740	0.0
Lockheed Martin Corp	2,902	0.0	2,902	0.0
SunEdison	1,973	0.0	1,973	0.0
GP Cellulose Holdings LLC	0	0.0	0	0.0
Reedy Creek Improvement District	0	0.0	0	0.0
Total	**83,986,702**	**100.0**	**82,548,719**	**100.0**
Pre-transaction HHI	8,726			
Post-transaction HHI	8,705			
HHI Change	-21			

Source: Hitachi Energy via Velocity Suite Intelligent Query,
EIA 923 Monthly Plant Generation & Consumption; Unit Generation and Emissions

APPENDIX 4

TESTIMONY OF TIM OLIVER

[See Attached]

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.	)	Docket No. EC25-___-000
Florida Power & Light Company	)	

PREPARED DIRECT TESTIMONY AND EXHIBITS

OF TIMOTHY OLIVER

June 10, 2025

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Vandolah Power Company L.L.C.	)	Docket No. EC25-___-000
Florida Power & Light Company	)	

PREPARED DIRECT TESTIMONY OF TIMOTHY OLIVER

I. INTRODUCTION

Q. Please state your name, business address, and position.

A. My name is Timothy Oliver. My business address is 700 Universe Boulevard, Juno Beach, Florida, 33408. I am Vice President of Development for Florida Power & Light Company ("FPL" or the "Company"), which is a wholly owned subsidiary of NextEra Energy, Inc. ("NextEra Energy").

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of FPL which, jointly with Vandolah Power Company L.L.C. ("Vandolah Power") (and collectively with FPL, the "Applicants"), is submitting an application seeking approval of the Federal Energy Regulatory Commission (the "Commission") under section 203 of the Federal Power Act ("FPA") of a proposed transaction pursuant to which FPL will (i) acquire Vandolah Power, the owner of the 660 MW (summer) Vandolah Generating Facility ("Vandolah") and, immediately thereafter, (ii) merge Vandolah Power into FPL, resulting in FPL becoming the direct and sole owner of Vandolah (collectively, the "Transaction").

Q. Please describe your educational background and professional experience.

A. Prior to my current role, I was Vice President of Renewable Origination and Prospecting for NextEra Energy Resources, LLC, where I led the team responsible for initiating utility-scale wind, solar, and battery storage projects and customer origination efforts across the U.S., with more than 15 years of experience in renewable energy development. Prior to that role, I served as Vice President of Corporate Real Estate at FPL, where I was responsible for the acquisition of the Company's first 10 GW of solar sites in its development pipeline.

I hold a Bachelor of Arts in Business Administration from James Madison University and a Master of Business Administration from the University of North Carolina. I am also a certified public accountant. I began my career working for KPMG's Washington, DC office.

Q. Have you previously testified before any regulatory commissions?

A. Yes, I have submitted testimony to the Florida Public Service Commission ("Florida PSC") in FPL's 2025 Rate Case proceeding.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to document the typical timeframe for developing new generation projects in Florida, and the integration of new energy sources, such as solar, battery storage, and natural gas-fired generation into FPL's system. Specifically, my testimony addresses the development life cycle of these facilities, the timing and planning required, and the efforts taken to ensure reliable energy for FPL customers within the proposed timelines.

Q. Are there any exhibits included with your testimony?

A. No.

III. GENERATION DEVELOPMENT LIFE CYCLE IN FLORIDA

Q. Please describe the typical development cycle of a new generating facility.

A. The development cycle of generation facilities in Florida varies depending on the type of facility being developed. Most natural gas-fired combined cycle generation projects begin with the issuance of a request for proposals ("RFP") as discussed below, followed by selection of the project, permitting, construction, and commencement of commercial operation. This development cycle typically takes roughly five years. Similar development activities are undertaken for simple cycle natural gas-fired combustion turbine generation projects and solar generation projects, although they generally are not initiated through RFPs, as discussed below. Given this and other factors, simple cycle natural gas-fired combustion turbines and solar generation have historically been developed in roughly two to three years. However, as further discussed below, supply chain bottlenecks are currently extending the development cycle for natural gas-fired combustion turbines.

Q. Why is issuance of a capacity RFP the typical beginning of combined cycle generation development in Florida?

A. The Florida PSC has adopted a rule requiring the use of RFPs to ensure that a utility's selection of any generation addition subject to the Florida Electrical Power Plant Siting Act ("PPSA"), *i.e.*, steam or solar generation 75 MW or greater, is the most cost-effective alternative available. *See* Florida Administrative Code Florida, PSC Rule 25-22.082(1) ("Bid Rule"); Florida Statutes Sections 403.501-403.518. The Bid Rule applies equally to new merchant generation procured by utilities through power purchase agreements. Therefore, the issuance of an RFP provides formal notice of the utility's intent to pursue a generation project subject to the PPSA either directly through a self-build or a purchase from an independent power producer ("IPP").

Q. Are municipal or cooperative utilities subject to the Florida PSC Bid Rule?

A. No. Similarly, while the Bid Rule does not apply directly to an IPP, an IPP could not develop a power plant subject to the PPSA unless it had a power purchase agreement with an electric utility fully committed to serving retail electric customers. In either case, the partnering retail electric utility would have been subject to the bid rule and the PPSA, such that the IPP project would face a similar development timeline.

Q. Can the RFP requirement be waived by the Florida PSC?

A. Yes. If the utility is able to demonstrate that a proposed generation facility will likely result in a lower cost supply of electricity to the utility's general body of ratepayers, increase the reliable supply of electricity to the utility's general body of ratepayers, or otherwise will serve the public welfare, the Florida PSC can exempt the utility from compliance with the Bid Rule. Bid Rule at 25-22.082(18). For example, the Florida PSC has waived the Bid Rule to allow FPL to undertake repowerings or modernizations of existing generation facilities. Moreover, upgrades to existing natural gas-fired generation facilities that add capacity, such as through the addition of wet compression or duct bank firing, are not subject to the PPSA and, therefore, not subject to the Bid Rule.

Q. How long does the RFP evaluation process typically last once the RFP is issued?

A. While the time to complete an RFP can vary from utility to utility, such processes typically take 8 to 10 months. At the conclusion of the RFP process (or the issuance of an order by the Florida PSC granting an exemption from the Bid Rule and its RFP requirement), the utility has identified the particular generation facility it intends to develop and initiates the permitting process.

Q. What about generation facilities that are not subject to the Bid Rule?

A. As noted above, utilities are required to comply with the Bid Rule only for generation projects that are subject to the PPSA, *i.e.*, steam or solar generation projects that are sized 75 MW or greater. Simple cycle combustion turbine generation projects like Vandolah do not fall under this requirement because they are neither steam nor solar generation. Solar generation projects in the state are typically sized below 75 MW, and projects at those capacities would not be subject to the PPSA or the Bid Rule. For simple cycle combustion turbines and solar generation below the PPSA threshold in Florida, the initiation of project development is formalized when the utility begins the permitting process.

Q. Please describe the permitting process.

A. The PPSA provides a single licensing process in Florida for steam electric or solar generating facilities that are 75 MW or greater. All other state and local permitting processes are preempted. The Site Certification process under the PPSA has specified statutory timeframes that dictate affected agencies reviews and public participation. The process begins with submitting a Site Certification Application to the Florida Department of Environmental Protection ("FDEP"), which coordinates with other affected state and local agencies. After the extensive agency review and administrative hearing, if required, the Florida Governor and Cabinet, sitting as the Power Plant Siting Board, or FDEP in some circumstances, issues the Final Order as a "Site Certification." Depending on the type of facility and proposed impacts, separate additional federal permits for impacts to waters of the United States, listed species, air and wastewater may be required. The State of Florida has federally delegated programs from the United States Environmental Protection Agency for industrial wastewater facilities and air quality permitting. Waters of the United States and listed species may require additional authorizations from the Army Corps of Engineers, United States Fish and Wildlife Service, or National Marine Fisheries Service. These permits are typically filed around the same time as the Site Certification Application is filed with the FDEP. Generation facilities not subject to the PPSA (*e.g.*, simple cycle combustion turbines and solar generation below the PPSA threshold, as noted above), must still obtain all relevant permits.

Q. How long does it take to complete the permitting process?

A. The process of obtaining necessary permits and licenses for an electric generation facility is iterative and can last well into the engineering and construction phase of the project. However, the preliminary permits or notices to proceed necessary to initiate construction, subject to receipt of final permits prior to commercial operation, are typically obtained within 12 to 18 months for natural gas-fired generation, with simple cycle combustion turbines moving more quickly than combined cycle generation, and six to 12 months for non-PPSA solar generation.

Q. Once permits are received, how long does construction take?

A. Facility construction generally consists of construction and commissioning of a new generating facility concluding at the in-service date of the facility. The duration of facility construction depends on several factors including the technology to be installed (*e.g.*, combined cycle natural gas-fired generation, simple cycle combustion turbines, or solar generation) and project-specific factors such as the condition of the site. Typically, construction of a new combined cycle generating facility takes 24 to 36 months, whereas construction of a new simple cycle combustion turbine takes 12 to 24 months and construction of a new solar generation project takes six to 12 months.

Q. Does the addition of battery storage to solar projects extend development timelines?

A. Yes, but only modestly. A solar plus battery storage hybrid project generally follows a similar timeline to a standalone solar farm. The solar array portion drives the project schedule, and utility-scale batteries (which are containerized and modular) can be installed in parallel with panel installation. The main difference is coordinating interconnection and control systems for both energy sources, which can add one to two months to the testing and commissioning process. Overall, new solar-plus-battery-storage facilities in Florida can be developed in roughly the same two- to three-year window as solar-only projects.

Q. Is this conclusion consistent with the observed development time of electric generation in Florida?

A. Yes. While a number of other generation projects under 20 MW have been developed in Florida since 2015, my review focused on larger projects as the development timeframe for smaller projects is not necessarily indicative of the timeline for larger projects. As it relates to natural gas-fired generation projects, my review incorporated FPL and other Florida utility projects based on publicly available information, which in some instances necessitated approximations due to data limitations. By contrast, my review of solar and battery projects consists of FPL project data, which is robust considering FPL has developed over 100 projects since 2015. As shown in the table below, the average time from initiation of a project to the in-service date was approximately 58 months (*i.e.*, roughly five years) for combined cycle generation, and 30 months each (*i.e.*, roughly three years) for combustion turbines, 32 months for solar projects (*i.e.*, between two and three years), and 22 months for BESS projects. As referenced previously in my testimony it is common to develop solar plus battery storage hybrid projects, which generally follow a similar timeline to a standalone solar farm.

Type	Project	Owner	Project Initiation	Constr. Start	In-Service	Devel. Cycle (Months)
Combined Cycle	Port Everglades	FPL	Aug-11	Jun-14	Apr-16	57
	Polk	TECO	Mar-12	Jan-14	Jan-17	59
	Crystal River (Citrus County)	DEF	Oct-13	Nov-15	Nov-18	62
	Okeechobee	FPL	Mar-15	Dec-16	Mar-19	49
	Dania	FPL	May-17	Jan-20	Jan-22	57
	Big Bend	TECO	Jun-18	Jun-20	Dec-22	55
	SCCF	Seminole	Dec-17	Mar-20	Apr-23	65
Simple Cycle	Fort Myers GT's	FPL	Feb-15	Sep-15	Dec-16	22
	Lauderdale GT's	FPL	Feb-15	Sep-15	Dec-16	22
	C.D McIntosh GT 2	Lakeland	Jul-18	Apr-19	Jun-20	23
	Big Bend CT 6	TECO	Jun-18	Aug-19	Nov-21	42
	Big Bend CT 5	TECO	Jun-18	Aug-19	Dec-21	43
	Gulf Clean Energy Center GT's	FPL	Jul-19	Oct-19	Dec-21	29
Solar	Anhinga	FPL	Jan-21	Apr-22	Jan-23	25
	Apalachee	FPL	Jun-20	Dec-21	Jan-23	32
	Babcock Preserve	FPL	Feb-18	May-19	Mar-20	26
	Beautyberry	FPL	Feb-22	Apr-23	Jan-24	24
	Big Juniper Creek	FPL	Dec-21	Jun-23	Mar-24	28
	Big Water	FPL	Jan-22	Apr-24	Jan-25	37
	Blackwater River	FPL	Jun-20	Apr-22	Jan-23	32
	Blue Heron	FPL	Jan-18	May-19	Mar-20	27
	Blue Indigo	FPL	Aug-18	Apr-19	Mar-20	19
	Blue Springs	FPL	Jan-19	Feb-21	Dec-21	36
	Bluefield Preserve	FPL	Oct-20	Apr-22	Jan-23	28
	Buttonwood	FPL	Jan-22	Jan-24	Nov-24	35
	Caloosahatchee	FPL	Sep-21	Apr-23	Jan-24	29
	Canoe	FPL	Sep-21	Apr-23	Jan-24	29
	Cattle Ranch	FPL	Feb-18	Apr-19	Mar-20	26

Type	Project	Owner	Project Initiation	Constr. Start	In-Service	Devel. Cycle (Months)
	Cavendish	FPL	Sep-20	Apr-22	Jan-23	29
Solar	Cedar Trail	FPL	Aug-22	Dec-23	Nov-24	28
	Chautauqua	FPL	Nov-19	Mar-22	Feb-23	40
	Chipola River	FPL	Mar-20	Dec-21	Jan-23	35
	Cotton Creek	FPL	Mar-19	Feb-21	Dec-21	34
	Cypress Pond	FPL	May-21	Jun-22	Jan-23	20
	Discovery	FPL	Jan-19	Jul-20	Jul-21	30
	Echo River	FPL	Aug-17	May-19	May-20	34
	Egret	FPL	Aug-18	Jan-20	Dec-20	28
	Elder Branch	FPL	Apr-19	Apr-21	Jan-22	34
	Etonia Creek	FPL	Feb-21	Jun-22	Jan-23	24
	Everglades	FPL	Oct-20	Jun-22	Jan-23	28
	Fawn	FPL	Dec-21	Apr-24	Jan-25	38
	First City	FPL	Aug-20	Mar-22	Jan-23	30
	Flowers Creek	FPL	Mar-20	Dec-21	Jan-23	35
	Fort Drum	FPL	Jul-19	May-20	Aug-21	26
	Fourmile Creek	FPL	Mar-22	Jun-23	Mar-24	25
	Fox Trail	FPL	Jun-22	Apr-24	Jan-25	32
	Georges Lake	FPL	Aug-18	Feb-24	Nov-24	77
	Ghost Orchid	FPL	Jun-17	Apr-21	Jan-22	57
	Green Pasture	FPL	Jan-22	Apr-24	Jan-25	37
	Grove	FPL	Jun-20	Apr-21	Jan-22	19
	Hawthorne Creek	FPL	Oct-21	Jun-23	Mar-24	30
	Hendry Isles	FPL	Aug-22	Oct-23	Nov-24	28
	Hibiscus	FPL	Aug-17	Apr-19	May-20	34
	Hog Bay	FPL	Jan-22	Apr-24	Jan-25	37
	Holopaw	FPL	Jan-22	Apr-24	Jan-25	37
	Honeybell	FPL	Jan-22	Feb-24	Nov-24	35
	Ibis	FPL	Mar-21	Apr-23	Jan-24	36
	Immokalee	FPL	Sep-20	Jun-21	Jan-22	17
	Interstate	FPL	Aug-16	Jul-18	Jan-19	30
	Kayak	FPL	May-22	Feb-24	Dec-24	32
	Lakeside	FPL	Aug-18	Nov-19	Dec-20	28
	Long Creek	FPL	Jan-22	Apr-24	Jan-25	37
	Magnolia Springs	FPL	Jan-19	Jan-20	Apr-21	28
	Miami-Dade	FPL	Oct-16	Jul-18	Jan-19	28
	Mitchell Creek	FPL	Mar-22	Dec-23	Nov-24	33
	Monarch	FPL	Sep-21	Apr-23	Jan-24	29
	Nassau	FPL	Jan-19	Jan-20	Dec-20	24

Type	Project	Owner	Project Initiation	Constr. Start	In-Service	Devel. Cycle (Months)
	Nature Trail	FPL	Oct-21	Jun-23	Mar-24	30
Solar	Northern Preserve	FPL	May-17	Feb-19	Jan-20	33
	Norton Creek	FPL	May-22	Nov-23	Dec-24	32
	Okeechobee	FPL	Aug-17	May-19	May-20	34
	Orange Blossom	FPL	Nov-18	May-20	Jul-21	33
	Orchard	FPL	Jan-22	Apr-23	Jan-24	25
	Palm Bay	FPL	Jan-19	May-20	May-21	29
	Pecan Tree	FPL	Feb-21	Jun-23	Mar-24	38
	Pelican	FPL	Nov-18	May-20	Apr-21	30
	Pineapple	FPL	Dec-21	Apr-23	Jan-24	25
	Pink Trail	FPL	Jan-21	Apr-22	Jan-23	25
	Prairie Creek	FPL	Nov-21	Apr-23	Jan-24	27
	Redlands	FPL	Apr-22	Apr-24	Jan-25	34
	Rodeo	FPL	Aug-17	May-20	May-21	47
	Sabal Palm	FPL	Aug-17	May-20	Jun-21	48
	Sambucus	FPL	Aug-21	Jun-23	Mar-24	32
	Saw Palmetto	FPL	Feb-21	Mar-22	Jan-23	24
	Sawgrass	FPL	Aug-18	Apr-21	Jan-22	42
	Shirer Branch	FPL	Feb-21	Mar-22	Feb-23	25
	Silver Palm	FPL	Feb-21	Apr-23	Jan-24	36
	Southfork	FPL	Aug-17	May-19	May-20	34
	Sparkleberry	FPL	Sep-21	Jun-23	Mar-24	30
	Speckled Perch	FPL	Jan-22	Apr-24	Jan-25	37
	Sundew	FPL	Aug-19	May-21	Jan-22	30
	Swallowtail	FPL	Aug-22	Apr-24	Jan-25	30
	Sweetbay	FPL	Aug-17	Apr-19	Mar-20	32
	Tenmile Creek	FPL	Sep-22	Apr-24	Jan-25	29
	Terrill Creek	FPL	Feb-21	Apr-23	Jan-24	36
	Thomas Creek	FPL	Oct-21	Apr-24	Jan-25	41
	Three Creeks	FPL	Aug-21	Jun-23	Mar-24	32
	Trailside	FPL	Mar-19	Nov-19	Dec-20	22
	Turnpike	FPL	Aug-21	Jan-23	Jan-24	30
	Twin Lakes	FPL	Sep-17	Feb-19	Mar-20	31
	Union Springs	FPL	Aug-17	Jan-20	Dec-20	42
	White Tail	FPL	Mar-21	Apr-23	Jan-24	35
	Wild Azalea	FPL	Jan-21	Mar-22	Feb-23	26
	Wild Quail	FPL	Feb-21	Jun-23	Mar-24	38
	Willow	FPL	Apr-19	Jun-20	Jul-21	28

Type	Project	Owner	Project Initiation	Constr. Start	In-Service	Devel. Cycle (Months)
	Woodyard	FPL	Feb-22	Jun-23	Mar-24	26
BESS	Babcock Ranch BESS	FPL	May-17	Dec-17	Mar-18	10
	Wynwood BESS	FPL	Feb-18	Mar-19	Dec-19	23
	Dania Beach BESS	FPL	Jun-19	Apr-20	Sep-20	15
	Echo River BESS	FPL	Sep-19	Feb-20	Dec-21	27
	Manatee Energy BESS	FPL	Apr-19	Aug-20	Dec-21	32
	Sunshine Gateway BESS	FPL	Oct-19	Apr-21	Dec-21	26

IV. TIMING OF PROJECT DEVELOPMENT

Q. How does the current supply chain environment impact the development of new natural gas-fired generation projects?

A. Several specific constraints are impacting the supply chains for new natural gas-fired turbines in the U.S. These include domestic factors and global issues such as manufacturing capacity, trade policies and tariffs, environmental regulations and compliance, labor shortages, and energy market dynamics. Together, these constraints are driving upward pressure on costs and increasing lead times for natural gas-fired turbine equipment and extending the typical development cycle for new natural gas-fired generation projects.

Q. What is the current timeframe for development of new natural gas-fired generation in light of current supply chain impacts?

A. For combined cycle gas-fired projects, the process, as discussed above, includes issuing an RFP, selecting the project, permitting, construction, and starting commercial operations, which are currently estimated to take about six years, inclusive of current supply chain constraints. Simple cycle natural gas-fired combustion turbine projects follow a similar development path but usually do not start with an RFP, as previously discussed. Consequently, these projects are currently estimated to take about three to five years to develop. Therefore, as compared to historical development timelines, the current supply chain constraints are affecting simple cycle combustion turbine projects more severely, on the order of one to two additional years on top of the typical two to three years, as compared to combined cycle units, which are only impacted by one year on top of the typical five years.

Q. Has the current supply chain environment impacted the development of solar and storage project?

A. No, we still estimate two to three years for solar and battery projects.

Q. What is the current timeframe for bringing new gas supply online for gas projects?

A. For new gas supply for Florida generating projects, we currently estimate a three to four year timeframe to secure new gas supplies and ensure pipelines and new compression stations are brought in to support these units. This includes contracting for gas supply, obtaining necessary permits, and constructing pipeline connections to the site. Note, however, that is not common to secure additional firm gas pipeline capacity for simple cycle combustion turbine projects, which typically operate with more of a peaking profile for only a small proportion of the year. For example, FPL plans to operate Vandolah using non-firm gas supply and will burn on-site fuel oil as a backup when available.

Q. When is FPL planning to bring new gas generating projects into the market?

A. As described in FPL's Ten Year Site Plan filed with the Florida PSC on April 1, 2025, FPL plans to build 475 MW of simple cycle combustion turbines at its Manatee Plant to be placed in service by January 1, 2032. This is part of our strategy to ensure we have sufficient generation capacity to meet anticipated demand growth and maintain grid reliability. The acquisition of Vandolah is an opportunity to bring cost effective generation capacity to FPL's service territory on a shorter timeframe compared to developing new generation while offsetting supply chain risks.

Q. From a customer perspective, how does acquiring an existing facility compare with building an equivalent resource or in the case of Vandolah, a portfolio of 400 MW of batteries in 2028 and the aforementioned combustion turbines at Manatee in 2032?

A. Acquiring an existing, fully operational 660 MW facility like Vandolah provides immediate capacity, which avoids capital cost inflation and risk premiums associated with new builds and eliminates interconnection uncertainty. In contrast, building an equivalent portfolio of new capacity would require permitting, separate interconnection paths, and significant capital expenditures over time. In this case, the Transaction replaces the need for 400 MW of four-hour BESSs and 475 MW of combustion turbines, thus averting supply chain uncertainties specific to peaking projects. Overall, it offers lower total cost, lower execution risk and greater timing certainty, translating into customer savings and reliability benefits.

V. PROPOSED NEW TRANSMISSION FACILITIES

Q. Provide an overview of the proposed new transmission facilities to integrate the acquired Vandolah facility into the FPL Balancing Authority Area.

A. FPL plans to build a new transmission substation (Bickett) along with an approximately 14.5-mile 230 kV transmission line to tie the Vandolah facility directly to the FPL system. The new Bickett substation will be built on existing FPL property, which is adjacent to two

FPL transmission lines which would be integrated into the station. The new transmission line will be a direct path from the station to the facility. This would allow the facility to then inject its output into the new FPL Bickett substation, and Vandolah would be re-registered with NERC as a resource in the FPL BAA. The target transmission line in-service date is June 1, 2027, concurrent with the closing date of the Vandolah acquisition.

Q. Is FPL confident that the proposed transmission facilities can be placed in-service by June 1, 2027?

A. Yes. The Company is confident that it will meet the in-service date because FPL has already developed a project schedule for these facilities, FPL currently owns the substation property, and FPL has already established the transmission path from Bickett to the facility.

FPL already began engineering and design of the new facilities as well as discussions with landowners along the planned right of way in May 2025, and intends to initiate purchases for long-lead equipment in July 2025. As a result, FPL expects that landowner easement discussions will be relatively straightforward, requiring only limited or no eminent domain proceedings. Where the planned route crosses other transmission facilities, roadways, or rail, FPL has planned the project with underground crossings to limit lengthy design planning and negotiations. The Vandolah facility has sufficient open space on the site for required facility additions, and FPL already owns land for the planned new Bickett substation that will interconnect the Vandolah facility and the new transmission line with the FPL system.

Because the transmission line is integrating a pre-existing generating facility and adds a new inter-tie between the FPL, Duke Energy Florida, and Seminole transmission systems, it is expected that the planned addition will have limited-to-no negative impacts to the broader transmission system. FPL expects to submit required environmental permitting packages to respective agencies by August 2025 and expects the permitting process to take 13 months. FPL will then be in a position to begin construction of the facilities in September 2026 and expects construction to take no longer than nine months, thereby meeting the June 1, 2027, in-service date. FPL has been developing and constructing high-voltage transmission lines in Florida for more than 100 years and has invested significantly in new transmission in Florida to be resilient and provide reliable, cost-effective transmission to all FPL customers. With its significant experience in these activities in the state of Florida, FPL has high confidence in its ability to execute this project on-time and on-budget.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX 5

PROPOSED ACCOUNTING ENTRIES

FPL provides below proposed accounting entries for the contemplated Transaction. Insofar as Vandolah Power Company L.L.C. is not required to maintain its books and records in accordance with the Commission's Uniform System of Accounts ("USoA"), FPL intends, after consummation of the Transaction, to estimate appropriate plant and accumulated depreciation values, in conformity with USoA Electric Plant Instruction 5.

To this effect, FPL has included in these proposed accounting entries placeholders for the to-be-determined values and respectfully requests waiver of any need to provide actual values at this time. Rather, actual values will be submitted, in accordance with Commission precedent, within six months of consummation of the Transaction. The Commission has in the past found this approach sufficient and should make the same finding here.[1]

Entries	**FERC Acct**	**Debit**	**Credit**
Electric Plant Purchased or Sold	102	$ A	
Cash	131		$ A

To record the acquisition of Vandolah in accordance with 18 CFR Part 101, Electric Plant Instruction 5A

Plant in Service	101	$ B	
Electric Plant Acquisition Accumulated	114	$ C	
Accumulated Provision for Depreciation	108		$ D
Electric Plant Purchased or Sold	102		$ E

To clear account 102, Electric Plant Purchased or Sold, and record the acquired assets in FPL's books and records in accordance with 18 CFR Part 101, Electric Plant Instruction 5B [Note that B + C will equal D + E]

[1] *See, e.g.*, *Tucson Elec. Power Co.*, Docket No. EC19-100-000, Application Pursuant to Federal Power Act Section 203 at 24, Appx. 3 (dated June 5, 2019) (providing proposed accounting entries with only placeholders rather than values).

APPENDIX 6

PROPOSED PROTECTIVE AGREEMENT

[See Attached]

PROTECTIVE AGREEMENT

This Protective Agreement ("Agreement") is entered into this ___ day of ___________, 2025, by and between Vandolah Power Company L.L.C. and Florida Power & Light Company (jointly, "Applicants") and ____________________ ("Intervenor"), and shall govern the use of all Privileged Materials produced by Applicants to Intervenor, or vice versa, in connection with the proceeding before the Federal Energy Regulatory Commission (the "Commission") in Docket No. EC25-___-000. Applicants and Intervenor are sometimes referred to herein individually as a "Party" or jointly as the "Parties."

1. Applicants filed in the above-referenced proceeding Privileged Material and/or Critical Energy/Electric Infrastructure Information ("CEII"), as those terms are defined herein. Intervenor is a Participant in such proceeding, as the term Participant is defined in 18 C.F.R. Section 385.102(b), or has filed a motion to intervene or a notice of intervention in such proceeding. Applicants and Intervenor enter into this Agreement to govern the use of Privileged Material and/or CEII produced by, or on behalf of, Applicants and/or Intervenor in the above-referenced proceeding. Notwithstanding any order terminating such proceeding, this Agreement shall remain in effect unless and until specifically modified or terminated by the Commission or court of competent jurisdiction.

2. The Commission's regulations[1] and its policy governing the labelling of controlled unclassified information ("CUI"),[2] establish and distinguish the respective designations of Privileged Material and CEII. As to these designations, this Agreement provides that a Party:

A. *may* designate as Privileged Material any material which customarily is treated by that Party as commercially sensitive or proprietary or material subject to a legal privilege, which is not otherwise available to the public, and which, if disclosed, would subject that Party or its customers to risk of competitive disadvantage or other business injury; and

B. *must* designate as CEII, any material that meets the definition of that term as provided by 18 C.F.R. §§ 388.113(a), (c).

3. For the purposes of this Agreement, the listed terms are defined as follows:

A. Party and Parties: As defined above.

B. Privileged Material:[3]

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[1] *Compare 1*8 C.F.R. § 388.112 *with 1*8 C.F.R. § 388.113.

[2] *Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff*, 82 Fed. Reg. 18,632 (Apr. 20, 2017) (issued by Commission Apr. 14, 2017).

[3] The Commission's regulations state that "[f]or the purposes of the Commission's filing requirements, non-CEII subject to an outstanding claim of exemption from disclosure under FOIA, . . ., will be referred to as privileged material." 18 C.F.R. § 388.112(a). The regulations further state that "[f]or material filed in proceedings set for trial-type hearing or settlement judge proceedings, a participant's access to material for which privileged treatment is claimed is governed by the presiding official's protective order." 18 C.F.R. § 388.112(b)(2)(v).

i. Material (including depositions) provided by a Party in response to discovery requests or filed with the Commission, and that is designated as Privileged Material by such Party;[4]

ii. Material that is privileged under federal, state, or foreign law, such as work-product privilege, attorney-client privilege, or governmental privilege, and that is designated as Privileged Material by such Party;[5]

iii. Any information contained in or obtained from such designated material;

iv. Any other material which is made subject to this Agreement by a Presiding Administrative Law Judge ("Presiding Judge") or the Chief Administrative Law Judge ("Chief Judge") in the absence of a Presiding Judge or where no presiding judge is designated, the Commission, any court, or other body having appropriate authority, or by agreement of the Parties (subject to approval by the relevant authority);

v. Notes of Privileged Material (memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses Privileged Material);[6] or

vi. Copies of Privileged Material.

vii. Privileged Material does not include:

a. Any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court; or

b. Information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Agreement.

C. Critical Energy/Electric Infrastructure Information ("CEII"): As defined at 18 C.F.R. §§ 388.113(a), (c).

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[4] *See infra* ¶ 11 for the procedures governing the labeling of this designation.

[5] The Commission's regulations state that "[a] presiding officer may, by order . . . restrict public disclosure of discoverable matter in order to . . . [p]reserve a privilege of a participant. . . ." 18 C.F.R. § 385.410(c)(3). To adjudicate such privileges, the regulations further state that "[i]n the absence of controlling Commission precedent, privileges will be determined in accordance with decisions of the Federal courts with due consideration to the Commission's need to obtain information necessary to discharge its regulatory responsibilities." 18 C.F.R. § 385.410(d)(1)(i).

[6] Notes of Privileged Material are subject to the same restrictions for Privileged Material except as specifically provided in this Agreement.

D. Non-Disclosure Certificate: The certificate attached to this Agreement, by which persons granted access to Privileged Material and/or CEII must certify their understanding that such access to such material is provided pursuant to the terms and restrictions of this Agreement, and that such persons have read the Agreement and agree to be bound by it. All executed Non-Disclosure Certificates must be provided to the Parties.

E. Reviewing Representative: A person who has signed a Non-Disclosure Certificate and who is:

i. Commission Trial Staff designated as such in this proceeding;

ii. An attorney who has made an appearance in this proceeding for a Party;

iii. Attorneys, paralegals, and other employees associated for purposes of this case with an attorney who has made an appearance in this proceeding on behalf of a Party;

iv. An expert or an employee of an expert retained by a Party for the purpose of advising, preparing for, submitting evidence or testifying in this proceeding;

v. A person designated as a Reviewing Representative by order of a Presiding Judge, the Chief Judge, or the Commission; or

vi. Employees or other representatives of Parties appearing in this proceeding with significant responsibility for this docket.

4. Privileged Material and/or CEII shall be made available under the terms of this Agreement only to Parties and only to their Reviewing Representatives as provided in Paragraphs 6-10 of this Agreement. The contents of Privileged Material, CEII, or any other form of information that copies or discloses such materials shall not be disclosed to anyone other than in accordance with this Agreement and shall be used only in connection with this specific proceeding.

5. All Privileged Material and/or CEII must be maintained in a secure place. Access to those materials must be limited to Reviewing Representatives specifically authorized pursuant to Paragraphs 7-9 of this Agreement.

6. Privileged Material and/or CEII must be handled by each Party and by each Reviewing Representative in accordance with the Non-Disclosure Certificate executed pursuant to Paragraph 9 of this Agreement. Privileged Material and/or CEII shall not be used except as necessary for the conduct of this proceeding, nor shall they (or the substance of their contents) be disclosed in any manner to any person except a Reviewing Representative who is engaged in this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Material and/or CEII, but such copies automatically become Privileged Material and/or CEII. Reviewing Representatives may make notes of Privileged Material, which shall be treated as Notes of Privileged Material if they reflect the contents of Privileged Material.

7. If a Reviewing Representative's scope of employment includes any of the activities listed under this Paragraph 7, such Reviewing Representative may not use information contained in any Privileged Material and/or CEII obtained in this proceeding for a commercial purpose (e.g., to give a Party or competitor of any Party a commercial advantage):

A. Energy marketing;

B. Direct supervision of any employee or employees whose duties include energy marketing; or

C. The provision of consulting services to any person whose duties include energy marketing.

8. If a Party wishes to designate a person not described in Paragraph 3.E above as a Reviewing Representative, the Party must seek agreement from the Party providing the Privileged Material and/or CEII. If an agreement is reached, the designee shall be a Reviewing Representative pursuant to Paragraph 3.D of this Agreement with respect to those materials. If no agreement is reached, the matter must be submitted to a Presiding Judge, the Chief Judge, or the Commission for resolution.

9. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Material and/or CEII pursuant to this Agreement until three business days after that Reviewing Representative first has executed and served a Non-Disclosure Certificate.[7] However, if an attorney qualified as a Reviewing Representative has executed a Non-Disclosure Certificate, any participating paralegal, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. Attorneys designated Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Agreement, and must take all reasonable precautions to ensure that Privileged Material and/or CEII are not disclosed to unauthorized persons. All executed Non-Disclosure Certificates must be served on the Parties.

10. Any Reviewing Representative may disclose Privileged Material and/or CEII to any other Reviewing Representative as long as both Reviewing Representatives have executed a Non-Disclosure Certificate. In the event any Reviewing Representative to whom Privileged Material and/or CEII are disclosed ceases to participate in this proceeding, or becomes employed or retained for a position that renders him or her ineligible to be a Reviewing Representative under Paragraph 3.D of this Agreement, access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Agreement and the Non-Disclosure Certificate for as long as the Agreement is in effect.

11. All Privileged Material and/or CEII in this proceeding filed with the Commission, submitted to a Presiding Judge, or submitted to any Commission personnel, must comply with the

[7]During this three-day period, a Party may file an objection with the other Party, a Presiding Judge or the Commission contesting that an individual qualifies as a Reviewing Representative, and the individual shall not receive access to the Privileged Material and/or CEII until resolution of the dispute.

Commission's *Notice cf Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission StTestimony*[8] Consistent with those requirements:

A. Documents that contain Privileged Material must include a top center header on each page of the document with the following text: CUI//PRIV. Any corresponding electronic files must also include this text in the file name.

B. Documents that contain CEII must include a top center header on each page of the document with the following text: CUI//CEII. Any corresponding electronic files must also include this text in the file name.

C. Documents that contain both Privileged Material and CEII must include a top center header on each page of the document with the following text: CUI//CEII/PRIV. Any corresponding electronic files must also include this text in the file name.

D. The specific content on each page of the document that constitutes Privileged Material and/or CEII must also be clearly identified. For example, lines or individual words or numbers that include both Privileged Material and CEII shall be prefaced and end with "BEGIN CUI//CEII/PRIV" and "END CUI//CEII/PRIV".

12. [Reserved]

13. If either Party desires to include, utilize, or refer to Privileged Material or information derived from Privileged Material in Testimony or other exhibits during the hearing in this proceeding in a manner that might require disclosure of such materials to persons other than Reviewing Representatives, that Party first must notify both counsel for the disclosing Party and any Presiding Judge, and identify all such Privileged Material. Thereafter, use of such Privileged Material will be governed by procedures determined by the Parties or, if applicable, the Presiding Judge.

14. Nothing in this Agreement shall be construed as precluding any Party from objecting to the production or use of Privileged Material and/or CEII on any appropriate ground.

15. Nothing in this Agreement shall preclude any Party from requesting a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority, to find this Agreement should not apply to all or any materials previously designated Privileged Material pursuant to this Agreement. A Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority may alter or amend this Agreement as circumstances warrant at any time during the course of this proceeding.

16. Each Party governed by this Agreement has the right to seek changes in it as appropriate from a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), the Commission, or any other body having appropriate authority.

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[8] 82 Fed. Reg. 18,632 (Apr. 20, 2017) (issued by the Commission Apr. 14, 2017).

17. Subject to Paragraph 19, a Presiding Judge (or the Chief Judge in a Presiding Judge's absence or where no presiding judge is designated), or the Commission shall resolve any disputes arising under this Agreement pertaining to Privileged Material according to the following procedures. Prior to presenting any such dispute to a Presiding Judge, the Chief Judge, or the Commission, the Parties to the dispute shall employ good faith best efforts to resolve it.

A. Any Party that contests the designation of material as Privileged Material shall notify the Party that provided the Privileged Material by specifying in writing the material for which the designation is contested.

B. In any challenge to the designation of material as Privileged Material, the burden of proof shall be on the Party seeking protection. If a Presiding Judge, the Chief Judge, or the Commission finds that the material at issue is not entitled to the designation, the procedures of Paragraph 19 shall apply.

C. The procedures described above shall not apply to material designated by a Party as CEII. Material so designated shall remain subject to the provisions of this Agreement, unless a Party requests and obtains a determination from the Commission's CEII Coordinator that such material need not retain that designation.

18. The designator will have five (5) days in which to respond to any pleading filed with a Presiding Judge, the Chief Judge, or the Commission requesting disclosure of Privileged Material. Should such Presiding Judge, the Chief Judge, or the Commission, as appropriate, determine that the information should be made public, such Presiding Judge, the Chief Judge, or the Commission will provide notice to the designator no less than five (5) days prior to the date on which the material will become public. This Agreement shall automatically cease to apply to such material on the sixth (6th) calendar day after the notification is made unless the designator files a motion with such Presiding Judge, the Chief Judge, or the Commission, as appropriate, with supporting Testimonys, demonstrating why the material should continue to be privileged. Should such a motion be filed, the material will remain confidential until such time as the interlocutory appeal or certified question has been addressed by the Motions Commissioner or Commission, as provided in the Commission's regulations, 18 C.F.R. §§ 385.714, 385.715. No Party waives its rights to seek additional administrative or judicial remedies after a Presiding Judge or Chief Judge decision regarding Privileged Material or the Commission's denial of any appeal thereof or determination in response to any certified question. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Privileged Material and/or CEII in the files of the Commission.

19. Privileged Material and/or CEII shall remain available to Parties until the later of 1) the date an order terminating this proceeding no longer is subject to judicial review, or 2) the date any other Commission proceeding relating to the Privileged Material and/or CEII is concluded and no longer subject to judicial review. After this time, the Party that produced the Privileged Material and/or CEII may request (in writing) that all other Parties return or destroy the Privileged Material and/or CEII. This request must be satisfied with within fifteen (15) days of the date the request is made. However, copies of filings, official transcripts and exhibits in this proceeding containing Privileged Material, or Notes of Privileged Material, may be retained if they are maintained in accordance with Paragraph 5 of this Agreement. If requested, each Party also must submit to the

Party making the request an Testimony stating that to the best of its knowledge it has satisfied the request to return or destroy the Privileged Material and/or CEII. To the extent Privileged Material and/or CEII are not returned or destroyed, they shall remain subject to this Agreement.

20. Nothing in this Agreement shall be deemed to preclude either Party from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced in this proceeding under this Agreement. Neither Party waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Privileged Material and/or CEII.

IN WITNESS WHEREOF, the Parties each have caused this Agreement to be signed by their respective duly authorized representatives as of the date first set forth above.

By: ____________________________

Name: __________________________

Title: __________________________

Representing Vandolah Power Company L.L.C.

By: ____________________________

Name: __________________________

Title: __________________________

Representing Intervenor

By: ____________________________

Name: __________________________

Title: __________________________

Representing Florida Power & Light Company

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Material and/or Critical Energy/Electric Infrastructure Information (CEII) is provided to me pursuant to the terms and restrictions of the Agreement dated ___________, _____, by and between Vandolah Power Company L.L.C., Florida Power & Light Company, and _____________________ concerning materials in Federal Energy Regulatory Commission Docket No. EC25-____-000 (the "Agreement"), that I have been given a copy of and have read the Agreement, and that I agree to be bound by it.

I understand that the contents of Privileged Material and/or CEII, any notes or other memoranda, or any other form of information that copies or discloses such materials, shall not be disclosed to anyone other than in accordance with the Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ____________________________________

Printed Name: ___________________________

Title: __________________________________

Representing: ___________________________

Date: __________________________________

EXHIBIT B

ENERGY SUBSIDIARIES AND ENERGY AFFILIATES

Energy subsidiaries and energy affiliates of Florida Power and Light Company operating in the Commission's Southeast MBR Region are described below on a Balancing Authority Area ("BAA") by BAA basis.

1. Duke Energy Florida, Inc. ("DEF") BAA

Bell Ridge Solar, LLC ("Bell Ridge Solar"). Bell Ridge Solar owns and operates a solar photovoltaic generating facility with 74.5 MW aggregate nameplate capacity, located in Gilchrist County, Florida, within the FPC (DEF) BAA. Bell Ridge Solar is authorized by the Commission to sell energy and capacity at market-based rates.[1] Bell Ridge Solar is party to a 20-year contract with Reedy Creek Improvement District.

Bronson Solar, LLC ("Bronson Solar"). Bronson Solar will own and operate a photovoltaic generating facility with a nameplate capacity of approximately 74.5 MW located in Gilchrist County, Florida, within the FPC (DEF) BAA. Bronson Solar is authorized by the Commission to sell energy and capacity at market-based rates.[2] All of Bronson Solar's capacity is fully committed on a firm basis through a 25-year contract with Seminole Electric Cooperative ("SEC").

FRP Columbia County Solar, LLC ("Columbia Solar"). Columbia Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 74.5 MW located in Columbia County, Florida, within the FPC (DEF) BAA. Columbia Solar is authorized by the Commission to sell energy and capacity at market-based rates.[3] All of Columbia Solar's capacity is fully committed on a firm basis through a 25-year contract with Seminole.

FRP Gadsden County Solar, LLC ("Gadsden Solar"). Gadsden Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 74.5 MW located in Gadsden County, Florida, within the FPC (DEF) BAA. Gadsden Solar is authorized by the Commission to sell energy and capacity at market-based rates.[4] All of Gadsden Solar's capacity is fully committed on a firm basis through a 25-year contract with Seminole.

FRP Gilchrist County Solar, LLC ("Gilchrist Solar"). Gilchrist Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 74.5 MW located in Gilchrist County, Florida, within the FPC (DEF) BAA. Gilchrist Solar is authorized by the Commission to sell energy and capacity at market-based rates.[5] All of Gilchrist Solar's capacity is fully committed on a firm basis through a 25-year contract with Seminole.

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[1] *See Bell Ridge Solar, LLC*, Docket No. ER23-883, Letter Order (issued Mar. 15, 2023).

[2] *See Bronson Solar, LLC*, Docket No. ER25-1437, Letter Order (issued Apr. 17, 2025).

[3] *See FRP Columbia County Solar, LLC*, Docket No. ER24-2512, Letter Order (issued Sept. 4, 2024).

[4] *See FRP Gadsden County Solar, LLC*, Docket No. ER24-2514, Letter Order (issued Sept. 4, 2024).

[5] *See FRP Gilchrist County Solar, LLC*, Docket No. ER24-2513, Letter Order (issued Sept. 4, 2024).

2. Florida Municipal Power Pool ("FMPP") BAA

Harmony Florida Solar, LLC ("Harmony Florida Solar"). Harmony Florida Solar owns and operates an approximately 74.5 MW solar photovoltaic generation facility located in Osceola County, Florida, within the FMPP BAA. Harmony Florida Solar is authorized by the Commission to sell energy and capacity at market-based rates.[6] The entire output of the Harmony Facility Solar is fully committed on a firm basis pursuant to separate long-term contracts with Orlando Utilities Commission ("OUC") and Florida Municipal Power Agency ("FMPA"), each of which has an initial term of 20 years, ending in 2040.

Harmony Florida Solar II, LLC ("Harmony Florida Solar II"). Harmony Florida Solar II owns and operates an approximately 74.5 MW solar photovoltaic generation facility located in Osceola County, Florida within the FMPP BAA. Harmony Florida Solar II operates under a power purchase agreement ("PPA") with OUC,[7] in which Harmony Florida Solar II sells its entire output on a firm basis to OUC, which has an initial term of 20 years, ending in 2044.

Stanton Clean Energy, LLC ("Stanton"). Stanton owns a 65 percent interest in Unit A of the Stanton Energy Center, located near Orlando, Florida in the FMPP BAA. Unit A of the Stanton Energy Center has multiple owners and each owner has control of its share of the facility.[8] Stanton's interest in Unit A of the facility provides Stanton with control over approximately 427 MW (summer rating). Unit A is a dual fuel, combined-cycle electric-generating unit. Stanton is authorized by the Commission to sell energy and capacity at market-based rates outside of Peninsular Florida and in the FPC (DEF), Jacksonville Electric Authority ("JEA"), SEC, and Tampa Electric Company ("TEC") BAAs.[9] Stanton's ownership share in Unit A of the Stanton Energy Center is fully committed. OUC has a long-term firm contract for 80 percent of the output of Stanton's share of Unit A through December 31, 2031. The remaining 20 percent share of Stanton's interest in Unit A is committed under a long-term firm contract with OUC through December 31, 2028.

Storey Bend Solar, LLC ("Storey Bend Solar"). Storey Bend Solar owns and operates an approximately 74.5 MW solar photovoltaic generation facility located in Osceola County, Florida within the FMPP BAA. Storey Bend Solar operates under a PPA with OUC,[10] in which Storey Bend Solar sells its entire output on a firm basis to OUC, which has an initial term of 20 years, ending in 2044.

Taylor Creek Solar, LLC ("Taylor Creek Solar"). Taylor Creek Solar owns and operates an approximately 74.5 MW solar photovoltaic generation facility located in Orange County, Florida within the FMPP BAA and is interconnected to the transmission system owned by OUC. Taylor Creek Solar is authorized by the Commission to sell energy and capacity at market-

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[6] *See Harmony Florida Solar, LLC*, 174 FERC ¶ 61,187 (2021).

[7] *See Harmony Florida Solar II, LLC, et al.*, 189 FERC ¶ 61,136 (2024).

[8] The other owners of the Stanton Energy Center Unit A are OUC, Kissimmee Utility Authority, and FMPA.

[9] *See Stanton Clean Energy, LLC*, Docket No. ER19-774, Letter Order (issued Mar. 5, 2019).

[10] *See Storey Bend Solar, LLC, et al.*, 189 FERC ¶ 61,136 (2024).

based rates.[11] The entire output of Taylor Creek is committed on a firm basis pursuant to a contract with OUC, which has an initial term ending in 2040.

3. Florida Power & Light ("FPL") BAA

FRP Tupelo Solar, LLC ("FRP Tupelo Solar"). FRP Tupelo Solar owns and operates an approximately 74.5 MW solar photovoltaic generation facility located in Putnam and Flagler Counties in Florida within the FPL BAA. FRP Tupelo Solar operates under a PPA with Seminole,[12] in which FRP Tupelo Solar sells its entire output on a firm basis to Seminole, which has an initial term of 25 years, ending in 2049.

NextEra Energy Marketing, LLC ("NEM"). NEM is an affiliated power marketer with its principal place of business in Juno Beach, Florida. NEM is authorized by the Commission to sell power at market-based rates.[13] NEM, however, does not own, control, or operate any generation in the region that is not otherwise deemed to be owned, controlled, or operated by NEM's affiliates. NEM is a wholly-owned direct subsidiary of NextEra Resources, which is a wholly-owned direct subsidiary of NextEra Energy Capital Holdings, which in turn is a wholly-owned direct subsidiary of NextEra.

NextEra Energy Services Massachusetts, LLC ("NES Mass"). NES Mass is a retail marketer and has nationwide authorization to sell energy, capacity, and ancillary services at market-based rates.[14] NES Mass does not own, control, or operate any generation in the region that is not otherwise deemed to be owned, controlled or operated by NES Mass' affiliates.

NEPM II, LLC ("NEPM II"). NEPM II is an affiliated power marketer with its principal place of business in Juno Beach, Florida. NEPM II is authorized by the Commission to sell power at market-based rates.[15] NEPM II, however, does not own, control, or operate any generation in the region that is not otherwise deemed to be owned, controlled, or operated by NEPM II's affiliates. NEPM II is a wholly-owned direct subsidiary of NEM, which in turn is a wholly-owned direct subsidiary of NextEra Resources, which is a wholly-owned direct subsidiary of NextEra Energy Capital Holdings, which in turn is a wholly-owned direct subsidiary of NextEra.

Oleander Power Project, Limited Partnership ("Oleander"). Oleander's generation facility is a dual fuel, simple-cycle combustion turbine electric-generating plant located near Cocoa, Florida, with a total capacity of approximately 778 MW (summer rating), that has discrete units within the FPL, SEC, and FMPP BAAs: Oleander Unit 1 is in the FPL BAA (155 MW summer rating); Oleander Units 2 through 4 are in the SEC BAA (466 MW summer rating); and Oleander Unit 5 is located in the FMPP BAA (157 MW summer rating). Oleander is authorized by the

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[11] *See Harmony Florida Solar, LLC*, 174 FERC ¶ 61,187 (2021).

[12] *See Storey Bend Solar, LLC*, *et al.*, 189 FERC ¶ 61,136 (2024).

[13] *See NextEra Energy Power Marketing, LLC*, Docket No. ER09-832, Letter Order (issued Apr. 16, 2009).

[14] *See NextEra Energy Services Massachusetts, LLC*, Docket No. ER10-1951, Letter Order (issued Jan. 21, 2011). NES Mass was originally granted market-based rate authorization under Docket No ER05-714, Letter Order (issued May 18, 2005).

[15] *See NEPM II, LLC*, Docket No. ER11-4462, Letter Order (issued Dec. 9, 2011).

Commission to sell energy and capacity at market-based rates outside of Peninsular Florida and in the DEF, JEA, SEC, and TEC BAAs.[16]

The entire output of Oleander is fully committed through long-term firm contracts and a lease with non-affiliates. Control of Oleander Units 1 and 4 (in the FPL BAA) is currently leased to Power Holding LLC, a subsidiary of General Electric Company (the "GE Lease"). Oleander Units 2 and 3 are fully committed under a long-term firm contract with SEC through December 31, 2027. Oleander Unit 5 is fully committed under a long-term firm contract with FMPA through December 31, 2027. Upon expiration of the contracts for Units 2, 3, and 5, control of those units will be transferred to Power Holding LLC under the GE Lease. The term of the GE Lease runs through December 31, 2029.

4. Jacksonville Electric Authority ("JEA") BAA

FRP Caldwell Solar, LLC ("FRP Caldwell Solar"). FRP Caldwell Solar will own and operate a 74.9 MW solar photovoltaic generating and a battery energy storage ("BESS") project with a capacity of 50 MW facility located in Duval County, Florida. FRP Caldwell Solar's application for authorization to sell energy and capacity at market-based rates is currently pending before the Commission.[17] All of FRP Caldwell Solar's capacity will be fully committed on a firm basis through a 35-year contract with JEA.

FRP Forest Trail Solar, LLC ("FRP Forest Trail Solar"). FRP Forest Trail Solar will own and operate a 50 MW solar photovoltaic generating facility in Duval County, Florida. FRP Forest Trail Solar's application for authorization to sell energy and capacity at market-based rates is currently pending before the Commission.[18] All of FRP Forest Trail's capacity will be fully committed on a firm basis through a 35-year contract with JEA.

FRP Miller Solar, LLC ("FRP Miller Solar"). FRP Miller Solar owns and operates a 74.9 MW solar photovoltaic generating facility and a 50 MW BESS project in Duval County, Florida. FRP Miller Solar's application for authorization to sell energy and capacity at market-based rates is currently pending before the Commission.[19] All of FRP Miller Solar's capacity will be fully committed on a firm basis through a 35-year contract with JEA.

5. South Carolina Electric & Gas Company BAA

Shaw Creek Solar, LLC ("Shaw Creek Solar"). Shaw Creek Solar owns and operates a solar photovoltaic generating facility with approximately 74.9 MW, located in Aiken County, South Carolina, within the South Carolina Gas & Electric BAA. Shaw Creek Solar is authorized by the Commission to sell energy and capacity at market-based rates.[20] All of Shaw Creek Solar's

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[16] *See Oleander Power Project, Limited Partnership*, Docket No. ER19-773, Letter Order (issued Apr. 17, 2019).

[17] *See FRP Caldwell Solar, LLC*, Docket No. ER25-1872, Letter Order (issued May 15, 2025).

[18] *See FRP Forest Trail Solar, LLC*, Docket No. ER25-1873, Letter Order (issued May 15, 2025).

[19] *See FRP Miller Solar, LLC*, Docket No. ER25-1874, Letter Order (issued May 15, 2025).

[20] *See Shaw Creek Solar, LLC*, Docket No. ER21-1506, Letter Order (issued Aug. 27, 2021).

capacity is fully committed on a firm basis through a 20-year contract with Dominion Energy South Carolina, with an initial term ending in 2039.

6. Southern Company Services, Inc. ("SOCO") BAA

Cool Springs Solar, LLC ("Cool Springs Solar"). Cool Springs Solar owns and operates a solar photovoltaic generating facility with 213 MW nameplate capacity and a BESS with 40 MW capacity, for a total of 253 MW (but limited to 213 MW of injections at the point of interconnection under the generator interconnection agreement). The project is located in Decatur County, Georgia, within the SOCO BAA. Cool Springs Solar is authorized by the Commission to sell energy and capacity at market-based rates.[21] All of Cool Springs Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2051.

Decatur Solar Energy Center, LLC ("Decatur Solar"). Decatur Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 200 MW located in Decatur County, Georgia, within the SOCO BAA. Decatur Solar is authorized by the Commission to sell energy and capacity at market-based rates.[22] All of Decatur Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company.

Dougherty County Solar, LLC ("Dougherty County Solar"). Dougherty County Solar leases and operates a photovoltaic generating facility with a nameplate capacity of approximately 120 MW located in Dougherty County, Georgia, in the SOCO BAA. Title to the facility is held by the Albany-Dougherty Payroll Development Authority, following the issuance of industrial revenue bonds. Dougherty County Solar is authorized by the Commission to sell energy and capacity at market-based rates.[23] All of Dougherty County Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2048.

Live Oak Solar, LLC ("Live Oak Solar"). Live Oak Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 51 MW located in Candler County, Georgia, within the SOCO BAA. Live Oak Solar is authorized by the Commission to sell energy and capacity at market-based rates.[24] All of Live Oak Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2046.

Quitman Solar, LLC ("Quitman Solar"). Quitman Solar leases and operates a photovoltaic generating facility with a nameplate capacity of approximately 150 MW located in Brooks County, Georgia. Title to the facility is held by the Brooks County Development Authority, following the issuance of industrial revenue bonds. Quitman Solar is authorized by the Commission to sell

[21] *See Cool Springs Solar, LLC*, Docket No. ER21-1519, Letter Order (issued May 12, 2021).

[22] *See Decatur Solar Energy Center, LLC*, Docket No. ER24-1289, Letter Order (issued Apr. 18, 2024).

[23] *See Dougherty County Solar, LLC*, Docket No. ER19-2269, Letter Order (issued Aug. 22, 2019).

[24] *See Live Oak Solar, LLC*, Docket No. ER16-1354, Letter Order (issued June 30, 2016).

energy and capacity at market-based rates.[25] All of Quitman Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2047.

Quitman Solar II, LLC ("Quitman Solar II"). Quitman Solar II owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 150 MW located in Brooks County, Georgia, within the SOCO BAA. Quitman Solar II is authorized by the Commission to sell energy and capacity at market-based rates.[26] All of Quitman Solar II's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2051.

Wadley Solar, LLC ("Wadley Solar"). Wadley Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 260 MW located in Decatur County, Georgia, within the SOCO BAA. Decatur Solar will soon file an application with the Commission to sell energy and capacity at market-based rates. All of Decatur Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company.

Washington County Solar, LLC ("Washington County Solar"). Washington County Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 150 MW located in Washington County, Georgia, within the SOCO BAA. Washington County Solar is authorized by the Commission to sell energy and capacity at market-based rates.[27] All of Washington County Solar's capacity is fully committed on a firm basis through a contract with Georgia Power Company, with an initial term ending in 2036.

White Oak Solar, LLC ("White Oak Solar"). White Oak Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 76.5 MW located in Burke County, Georgia within the SOCO BAA. White Oak Solar is authorized by the Commission to sell energy and capacity at market-based rates.[28] All of White Oak Solar's capacity is fully committed on a firm basis through a contract with Georgia Power Company, with an initial term ending in 2036.

White Pine Solar, LLC ("White Pine Solar"). White Pine Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 101.3 MW located in Taylor County, Georgia within the SOCO BAA. White Pine Solar is authorized by the Commission to sell energy and capacity at market-based rates.[29] All of White Oak Solar's capacity is fully committed on a firm basis through a 20-year contract with Georgia Power Company, with an initial term ending in 2036.

NextEra Energy Pipeline Holdings (Lowman), LLC ("Lowman Pipeline"). NextEra owns 85% of Lowman Pipeline. Lowman Pipeline owns an approximately 51-mile-long pipeline in

[25] *See Quitman Solar, LLC*, Docket No. ER19-2266, Letter Order (issued Aug. 16, 2019).

[26] *See Quitman Solar II, LLC*, Docket No. ER21-1532, Letter Order (issued May 12, 2021).

[27] *See Washington County Solar, LLC*, Docket No. ER24-1288, Letter Order (issued Apr. 18, 2024).

[28] *See White Oak Solar, LLC*, Docket No. ER16-1293, Letter Order (issued June 21, 2016).

[29] *See White Pine Solar, LLC*, Docket No. ER16-1277, Letter Order (issued June 21, 2016).

Choctaw and Washington Counties, Alabama that delivers gas from an interconnection with two interstate natural gas pipelines near Butler, Alabama to a non-affiliated gas-fired generation plant near Leroy, Alabama. As an intrastate pipeline, Lowman Pipeline is exempt from Commission jurisdiction pursuant to Section 1(c) of the Natural Gas Act.

7. Tennessee Valley Authority ("TVA")

Elora Solar, LLC ("Elora Solar"). Elora Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 150 MW located in Lincoln County, Tennessee within the TVA BAA. Elora Solar is authorized by the Commission to sell energy and capacity at market-based rates.[30] All of Elora Solar's capacity is fully committed on a firm basis through a 30-year contract with Georgia Power Company, with an initial term ending in 2046.

River Bend Solar, LLC ("River Bend Solar"). River Bend Solar owns and operates a photovoltaic generating facility with a nameplate capacity of approximately 75 MW located in Lauderdale County, Alabama within the TVA BAA. River Bend Solar is authorized by the Commission to sell energy and capacity at market-based rates.[31] All of River Bend Solar's capacity is fully committed on a firm basis through a 20-year contract with TVA, with an initial term ending in 2037.

[30] *See Elora Solar, LLC*, Docket No. ER21-1682, Letter Order (issued June 7, 2021).

[31] *See River Bend Solar, LLC*, Docket No. ER16-1913, Letter Order (issued Aug. 2, 2016).

EXHIBIT I

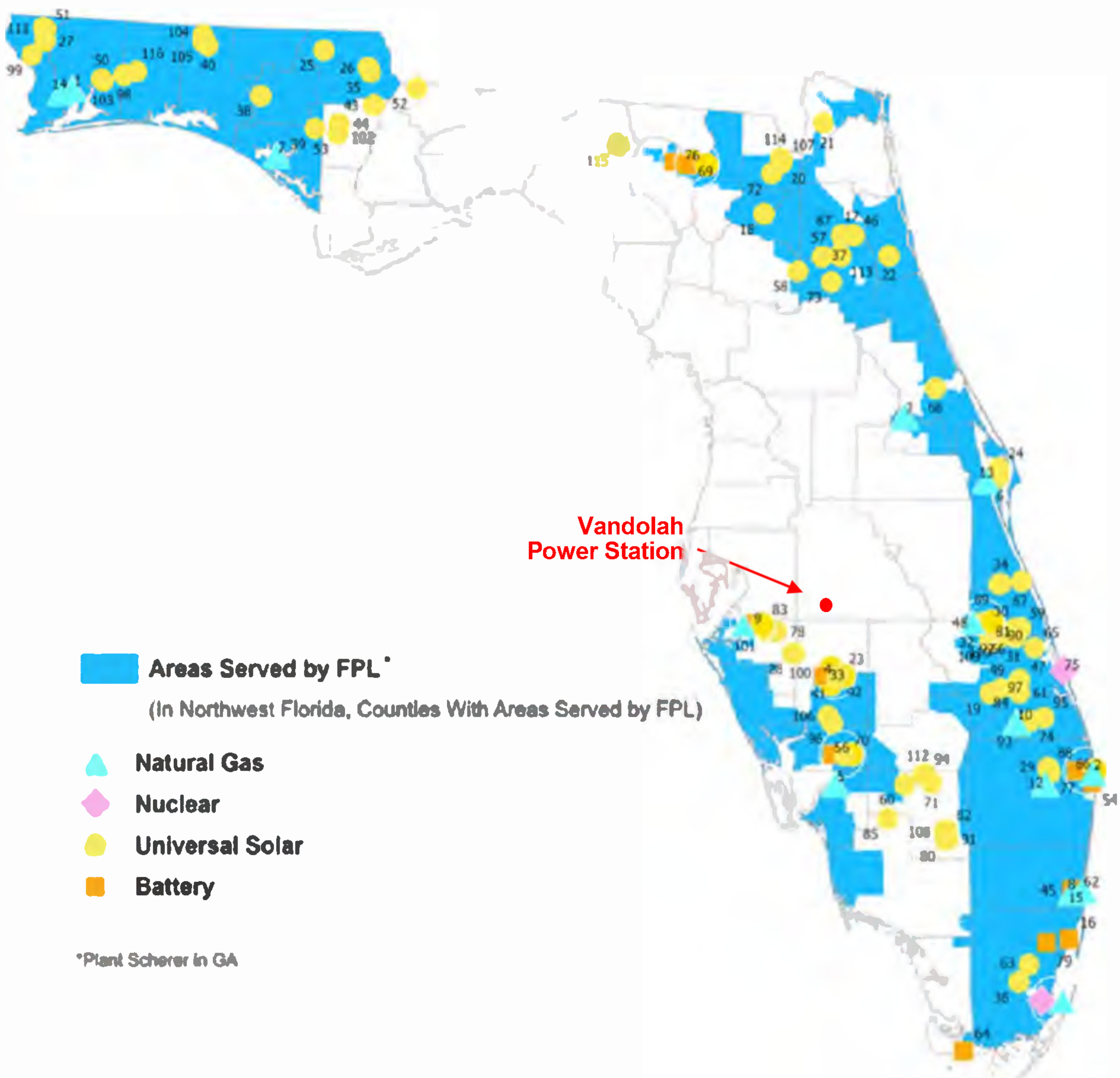
CONTRACTS RELATED TO THE TRANSACTION [PUBLIC]

[Information Removed for Privileged Treatment]

EXHIBIT K

KEY MAP

Florida Power & Light Service Territories and Generating Facilities, and Vandolah Power Station



(Key to power plants on following pages.)

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1]
	Nuclear				
75	St. Lucie [2]	St. Lucie County, FL	2	Nuclear	1,821
11	Turkey Point	Miami-Dade County, FL	2	Nuclear	1,681
	Total Nuclear:		4		3,502
	Coal Steam				
-	Scherer*	Monroe County, Ga	1	Coal	215
	Total Coal Steam:		1		215
	Combined-Cycle				
5	Fort Myers	Lee County, FL	1	Gas	1,822
9	Manatee	Manatee County, FL	1	Gas	1,246
3	Sanford	Volusia County, FL	2	Gas	2,418
7	Lansing Smith*	Bay County, FL	1	Gas	641
13	Cape Canaveral	Brevard County, FL	1	Gas/Oil	1,290
10	Martin	Martin County, FL	3	Gas/Oil	2,223
55	Okeechobee [3]	Okeechobee County, FL	1	Gas/Oil	1,720
62	Port Everglades	City of Hollywood, FL	1	Gas/Oil	1,237
2	Riviera Beach	City of Riviera Beach, FL	1	Gas/Oil	1,290
11	Turkey Point	Miami-Dade County, FL	1	Gas/Oil	1,292
12	West County	Palm Beach County, FL	3	Gas/Oil	3,771
45	Dania Beach Clean Energy Center	Broward County, FL	1	Gas/Oil	1,246
	Total Combined Cycle:		17		20,196
	Gas/Oil Steam				
9	Manatee [4]	Manatee County, FL	2	Gas/Oil	0
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas Steam	961
	Total Oil/Gas Steam:		6		961
	Gas Turbines(GT)				
5	Fort Myers (GT)	Lee County, FL	2	Oil	102
8	Lauderdale (GT)	Broward County, FL	2	Gas/Oil	69
	Total Gas Turbines/Diesels:		4		171
	Combustion Turbines				
8	Lauderdale	Broward County, FL	5	Gas/Oil	1,155
5	Fort Myers	Lee County, FL	4	Gas/Oil	852
1	Pea Ridge*	Santa Rosa County, FL	3	Gas	12
7	Lansing Smith*	Bay County, FL	1	Oil	32
14	Gulf Clean Energy Center*	Escambia County, FL	4	Gas	926
	Total Combustion Turbines:		17		2,977
	Land Fill Gas				
69	Perdido LFG*	Escambia County, FL	2	LFG	3
	Total LFG:		2		3

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1]
	Battery Storage				
9	Manatee Battery Storage	Manatee County, FL	1	Storage	409
69	Sunshine Gateway Battery Storage	Columbia County, FL	1	Storage	30
76	Echo River Battery Storage	Suwannee County, FL	1	Storage	30
	Total Battery Storage:		3		469
	PV				
4	DeSoto Solar	DeSoto County, FL	1	Solar Energy	25
56	Babcock Ranch Solar	Charlotte County, FL	1	Solar Energy	74.5
41	Citrus Solar	DeSoto County, FL	1	Solar Energy	74.5
9	Manatee Solar	Manatee County, FL	1	Solar Energy	74.5
6	Space Coast Solar	Brevard County, FL	1	Solar Energy	10
65	Interstate Solar	St. Lucie County, FL	1	Solar Energy	74.5
63	Miami Dade Solar	Miami-Dade County, FL	1	Solar Energy	74.5
68	Pioneer Trail Solar	Volusia County, FL	1	Solar Energy	74.5
69	Sunshine Gateway Solar	Columbia County, FL	1	Solar Energy	74.5
58	Horizon Solar	Alachua County, FL	1	Solar Energy	74.5
42	Wildflower Solar	DeSoto County, FL	1	Solar Energy	74.5
66	Indian River Solar	Indian River County, FL	1	Solar Energy	74.5
57	Coral Farms Solar	Putnam County, FL	1	Solar Energy	74.5
60	Hammock Solar	Hendry County, FL	1	Solar Energy	74.5
67	Barefoot Bay Solar	Brevard County, FL	1	Solar Energy	74.5
59	Blue Cypress Solar	Indian River County, FL	1	Solar Energy	74.5
61	Loggerhead Solar	St. Lucie County, FL	1	Solar Energy	74.5
70	Babcock Preserve Solar	Charlotte County, FL	1	Solar Energy	74.5
71	Blue Heron Solar	Hendry County, FL	1	Solar Energy	74.5
23	Cattle Ranch Solar	DeSoto County, FL	1	Solar Energy	74.5
76	Echo River Solar	Suwannee County, FL	1	Solar Energy	74.5
20	Egret Solar	Baker County, FL	1	Solar Energy	74.5
77	Hibiscus Solar	Palm Beach County, FL	1	Solar Energy	74.5
19	Lakeside Solar	Okeechobee County, FL	1	Solar Energy	74.5
21	Nassau Solar	Nassau County, FL	1	Solar Energy	74.5
72	Northern Preserve Solar	Baker County, FL	1	Solar Energy	74.5
55	Okeechobee Solar	Okeechobee County, FL	1	Solar Energy	74.5
78	Southfork Solar	Manatee County, FL	1	Solar Energy	74.5
74	Sweetbay Solar	Martin County, FL	1	Solar Energy	74.5
22	Trailside Solar	St. Johns County, FL	1	Solar Energy	74.5
73	Twin Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
18	Union Springs Solar	Union County, FL	1	Solar Energy	74.5
17	Magnolia Springs Solar	Clay County, FL	1	Solar Energy	74.5
31	Pelican Solar	St. Lucie County, FL	1	Solar Energy	74.5
34	Palm Bay Solar	Brevard County, FL	1	Solar Energy	74.5
33	Rodeo Solar	DeSoto County, FL	1	Solar Energy	74.5
24	Discovery Solar	Brevard County, FL	1	Solar Energy	74.5
30	Orange Blossom Solar	Indian River County, FL	1	Solar Energy	74.5

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [1]
	PV Continued				
29	Sabal Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
32	Fort Drum Solar	Okeechobee County, FL	1	Solar Energy	74.5
28	Willow Solar	Manatee County, FL	1	Solar Energy	74.5
82	Ghost Orchid Solar	Hendry County, FL	1	Solar Energy	74.5
80	Sawgrass Solar	Hendry County, FL	1	Solar Energy	74.5
84	Sundew Solar	St. Lucie County, FL	1	Solar Energy	74.5
85	Immokalee Solar	Collier County, FL	1	Solar Energy	74.5
81	Grove Solar	Indian River County, FL	1	Solar Energy	74.5
83	Elder Branch Solar	Manatee County, FL	1	Solar Energy	74.5
25	Blue Indigo Solar*	Jackson County, FL	1	Solar Energy	74.5
26	Blue Springs Solar*	Jackson County, FL	1	Solar Energy	74.5
27	Cotton Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
46	Anhinga Solar	Clay County, FL	1	Solar Energy	74.5
35	Apalachee Solar*	Jackson County, FL	1	Solar Energy	74.5
50	Blackwater Solar*	Santa Rosa County, FL	1	Solar Energy	74.5
49	Bluefield Preserve Solar	St. Lucie County, FL	1	Solar Energy	74.5
48	Cavendish Solar	Okeechobee County, FL	1	Solar Energy	74.5
40	Chautauqua Solar*	Walton County, FL	1	Solar Energy	74.5
43	Chipola Solar*	Calhoun County, FL	1	Solar Energy	74.5
38	Cypress Pond Solar*	Washington County, FL	1	Solar Energy	74.5
37	Etonia Creek Solar	Putnam County, FL	1	Solar Energy	74.5
36	Everglades Solar	Miami-Dade County, FL	1	Solar Energy	74.5
51	First City Solar*	Escambia County, FL	1	Solar Energy	74.5
44	Flowers Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
47	Pink Trail Solar	St. Lucie County, FL	1	Solar Energy	74.5
39	Saw Palmetto Solar*	Bay County, FL	1	Solar Energy	74.5
53	Shirer Branch Solar*	Calhoun County, FL	1	Solar Energy	74.5
52	Wild Azalea Solar*	Gadsden County, FL	1	Solar Energy	74.5
91	Beautyberry Solar	Hendry County, FL	1	Solar Energy	74.5
94	Caloosahatchee Solar	Hendry County, FL	1	Solar Energy	74.5
98	Canoe Solar*	Okaloosa County, FL	1	Solar Energy	74.5
89	Ibis Solar	Brevard County, FL	1	Solar Energy	74.5
93	Monarch Solar	Martin County, FL	1	Solar Energy	74.5
90	Orchard Solar	Indian River/St. Lucie County, FL	1	Solar Energy	74.5
97	Pineapple Solar	St. Lucie County, FL	1	Solar Energy	74.5
96	Prairie Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
88	Silver Palm Solar	Palm Beach County, FL	1	Solar Energy	74.5
87	Terrill Creek Solar	Clay County, FL	1	Solar Energy	74.5
92	Turnpike Solar	Indian River County, FL	1	Solar Energy	74.5
95	White Tail Solar	Martin County, FL	1	Solar Energy	74.5
103	Big Juniper Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
102	Fourmile Creek Solar*	Calhoun County, FL	1	Solar Energy	74.5
106	Hawthorne Creek Solar	DeSoto County, FL	1	Solar Energy	74.5
107	Nature Trail Solar	Baker County, FL	1	Solar Energy	74.5

Map Key #	Unit Type/ Plant Name	Location	Number of Units	Fuel	Summer MW [2]
	PV [3] Continued				
104	Pecan Tree Solar*	Walton County, FL	1	Solar Energy	74.5
100	Sambucus Solar	Manatee County, FL	1	Solar Energy	74.5
99	Sparkleberry Solar*	Escambia County, FL	1	Solar Energy	74.5
101	Three Creeks Solar	Manatee County, FL	1	Solar Energy	74.5
105	Wild Quail Solar*	Walton County, FL	1	Solar Energy	74.5
108	Woodyard Solar	Hendry County, FL	1	Solar Energy	74.5
110	Buttonwood Solar	St. Lucie County, FL	1	Solar Energy	74.5
114	Cedar Trail Solar	Baker County, FL	1	Solar Energy	74.5
113	Georges Lakes Solar	Putnam County, FL	1	Solar Energy	74.5
112	Hendry Isles Solar	Hendry County, FL	1	Solar Energy	74.5
109	Honeybell Solar	Okeechobee County, FL	1	Solar Energy	74.5
111	Mitchell Creek Solar*	Escambia County, FL	1	Solar Energy	74.5
116	Kayak Solar*	Okaloosa County, FL	1	Solar Energy	74.5
115	Norton Creek Solar	Madison County, FL	1	Solar Energy	74.5
	Total Nameplate PV:		**96**		**7,038**
		Total Units:	**150**		**35,531**
		Nameplate System Generation as of December 31, 2024 =			**35,531**
		Firm System Generation as of December 31, 2024 =			**31,691**

EXHIBIT M

DISCUSSION OF CROSS-SUBSIDIZATIONS, PLEDGES OR ENCUMBRANCES

Section 33.2(j) of the Commission's regulations provides that an application under Section 203 of the Federal Power Act shall contain, in an Exhibit M, an explanation:

> [o]f how applicants are providing assurance, based on facts and circumstances known to them or that are reasonably foreseeable, that the proposed transaction will not result in, at the time of the transaction or in the future, cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company[.][1]

Applicants submit, based on facts and circumstances known to them or that are reasonably foreseeable, that the proposed Transaction will not result in, at the time of the Transaction or in the future, cross-subsidization of a non-utility associate company or pledge or encumbrance of utility assets for the benefit of an associate company. In support thereof, Applicants state as follows.[2]

(a) But for debt issued by FPL, which is entirely of a form and nature common in the industry and has been approved by the Florida PSC, no Applicant has pledged or encumbered any utility assets.[3]

(b) The Transaction is fully arms' length and between two unaffiliated entities. Thus, the Transaction does not involve:

(i) "[a]ny transfer of facilities between a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, and an associate company,"[4]

(ii) "[a]ny new issuance of securities by a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company,"[5]

(iii) "[a]ny new pledge or encumbrance of assets of a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, for the benefit of an associate company,"[6] or

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[1] 18 C.F.R. § 33.2(j) (emphasis in original).

[2] *See id.*

[3] *See id.* § 33.2(j)(1)(i).

[4] *Id.* § 33.2(j)(1)(ii)(A).

[5] *Id.* § 33.2(j)(1)(ii)(B).

[6] *Id.* § 33.2(j)(1)(ii)(C).

(iv) "[a]ny new affiliate contract between a non-utility associate company and a traditional public utility associate company that has captive customers or that owns or provides transmission service over jurisdictional transmission facilities, other than non-power goods and services agreements subject to review under sections 205 and 206 of the Federal Power Act."[7]

[7] *Id.* § 33.2(j)(1)(ii)(D).

THE PUBLIC UTILITIES COMMISSION OF OHIO

IN THE MATTER OF THE APPLICATION OF OHIO POWER COMPANY FOR NEW TARIFFS RELATED TO DATA CENTERS AND MOBILE DATA CENTERS.	CASE NO. 24-508-EL-ATA

OPINION AND ORDER

Entered in the Journal on July 9, 2025

TABLE OF CONTENTS

I. Summary

{¶ 1} The Commission adopts the joint stipulation and recommendation filed by various parties on October 23, 2024, as modified herein.

II. Procedural

A. Procedural History

{¶ 2} Ohio Power Company (AEP Ohio or the Company) is a public utility, as that term is defined in R.C. 4905.02 and, as such, is subject to the jurisdiction of this Commission.

{¶ 3} On May 13, 2024, AEP Ohio filed an application, pursuant to R.C. 4909.18, requesting approval of the following tariffs to establish two new customer classifications: (1) the Data Center Power tariff for new data center customers that will use a monthly maximum demand of 25 megawatts (MW) or greater at a single location; and (2) the Mobile Data Center tariff for new mobile data center customers (such as cryptocurrency miners) that will use a monthly maximum demand of 1 MW or greater at a single location. (AEP Ex. 1).

{¶ 4} By Entry issued May 16, 2024, the administrative law judge (ALJ) scheduled a technical conference to be held on May 30, 2024, at 10:00 a.m., at the offices of the Commission.

{¶ 5} On May 20, 2025, the ALJ established a comment period, during which initial comments were due on June 10, 2024 and reply comments were due June 20, 2024. On June 7, 2024, the ALJ amended the comment period such that initial comments were due by June 25, 2024 and reply comments were due by July 8, 2024.

{¶ 6} The technical conference was held as scheduled on May 30, 2024.

{¶ 7} On June 25, 2024, numerous entities timely filed initial comments.

{¶ 8} On July 8, 2024, numerous entities timely filed reply comments.

{¶ 9} Also on various dates, multiple individuals and entities filed public comments in this case docket.

{¶ 10} By Entry issued September 3, 2024, the ALJ granted the following parties intervention in this proceeding: Ohio Energy Group (OEG); Interstate Gas Supply, LLC (IGS); Amazon Data Services, Inc. (ADS); Data Center Coalition (DCC); Walmart Inc. (Walmart); Google LLC (Google); Enchanted Rock, LLC (Enchanted Rock); The Ohio Manufacturers' Association Energy Group (OMAEG); the Office of the Ohio Consumers' Counsel (OCC); One Power Company f/k/a One Energy Enterprises Inc. (One Power)[1]; the Retail Energy Supply Association; Constellation NewEnergy, Inc. and Constellation Energy Generation LLC, jointly (Constellation); Microsoft Corporation (Microsoft); Sidecat, LLC (Sidecat); Ohio Partners for Affordable Energy (OPAE); Ohio Energy Leadership Council (OELC); The Ohio Blockchain Council (OBC); Calpine Retail Holdings, LLC; Buckeye Power, Inc. (Buckeye); and American Municipal Power, Inc (AMP).

{¶ 11} On October 10, 2024, a joint stipulation and recommendation (10/10 Stipulation) was filed by Microsoft, DCC, ADS, Google, Sidecat, Constellation, Enchanted Rock, IGS, Blockchain, OELC, OMAEG, One Power, and RESA.

{¶ 12} On October 23, 2024, AEP Ohio filed a joint stipulation and recommendation (10/23 Stipulation), signed by AEP Ohio, Staff, OEG, OCC, Walmart, and OPAE.

{¶ 13} By Entry dated October 25, 2024, the ALJ scheduled the evidentiary hearing to commence on December 3, 2024, and established specific testimony filing deadlines respective to the joint stipulations and recommendations filed on October 10, 2024, and October 23, 2024. Also in the Entry, the discovery response time was shortened to five business days and could be conducted until November 12, 2024.

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1 On October 28, 2024, a notice was filed indicating One Power Enterprises Inc. changed its name to One Power Company.

{¶ 14} The evidentiary hearing commenced as scheduled on December 3, 2024, at the Commission's offices.

{¶ 15} On December 5, 2024, due to an unforeseen medical emergency, the hearing was adjourned for the day and the proceedings were scheduled to reconvene the following day. At the outset of the proceedings on December 6, 2024, it was determined that the evidentiary hearing could not proceed as contemplated; and the ALJs continued the hearing to reconvene on December 11, 2024.

{¶ 16} During the evening of December 9, 2024, counsel for OBC served all parties and the ALJs a courtesy copy of a motion for continuance with a request for expedited treatment. On December 10, 2024, OMAEG filed a letter supporting OBC's motion for continuance.

{¶ 17} By Entry on December 10, 2024, the ALJ granted OBC's motion to continue the hearing to January 6, 2025.

{¶ 18} On December 11, 2024, the ALJ issued an Entry scheduling a local public hearing for January 3, 2025, at the Commission's offices and ordered AEP Ohio to issue a public notice.

{¶ 19} On January 6, 2025, the evidentiary hearing reconvened and finished on January 17, 2025.

{¶ 20} AEP Ohio, Staff, OCC and OPAE, Walmart, OEG, DCC, ADS, Google, Sidecat, OMAEG, OBC, Constellation, IGS, RESA, jointly, Buckeye and American Municipal Power, Inc., One Power, Enchanted Rock, and OELC filed timely initial briefs. Staff, IGS, Walmart, the Company, OMAEG, One Power, ADS, OMAEG, OBC, Constellation, RESA, Google, DCC, Sidecat, OEG, and, jointly OCC and OPAE filed timely reply briefs.

B. *Procedural Issues*

1. One Power's Motion to Dismiss

{¶ 21} On August 5, 2024, One Power filed a motion to dismiss this proceeding, claiming that AEP Ohio's application failed to comply with the requirements of R.C. 4909.18. One Power states that AEP Ohio filed its application as a request to increase rates pursuant to R.C. 4909.18, which requires a filing of a complete operating statement and anticipated income and expenses. Relatedly, One Power asserts that AEP Ohio did not submit a requisite verification of the application from an AEP Ohio president, vice-president, secretary, or treasurer. One Power thus requests the Commission to grant its motion to dismiss and force AEP Ohio to start over its application process and conform with R.C. 4909.18's requirements for an 'increase in rates' application.

{¶ 22} In response, AEP Ohio filed a memorandum contra to the motion to dismiss on August 20, 2024, generally asserting that One Power misinterprets the Company's application and R.C. 4909.18's requirements. The Company emphasizes that while R.C. 4909.18 can be used to establish a new service/rate or modify a service/rate, the key procedural distinction is whether the application involves an increase of rates or not an increase. On this point, AEP Ohio insists that its application is not for an increase in rates but proposes entirely new terms and conditions under new rate schedules. Furthermore, the Company asserts that no customers would see an increase in rates due to the proposed grandfathering provisions. Moreover, AEP Ohio asserts that only applications for an increase in rates require a verification from an AEP Ohio executive under R.C. 4909.18 and applications not for an increase in rates do not require such verification.

{¶ 23} On August 20, 2024, OCC also filed a memorandum contra to One Power's motion to dismiss. OCC asserts that forcing AEP Ohio to start its process over would hurt residential consumers, given the immediacy of the unprecedented load growth caused by data center customers. OCC states that the proceeding offers a critical opportunity to implement solutions that would ensure fair cost allocation for grid investments caused by incoming data center customers.

{¶ 24} On August 27, 2024, One Power filed a reply in support of its motion, mainly arguing that starting over would not only result in AEP Ohio complying with Ohio law, but also prevent a regulated monopoly from raising rates to customers without having to file for an increase in rates. One Power laments that AEP Ohio's proposed schedule is almost identical to Schedule GS and should not be treated as a first-filing of a brand new schedule as purported by AEP Ohio. Further, One Power is unpersuaded by AEP Ohio's reassurance that the grandfather provisions in the application would ensure that existing customers would not be subject to an increase in rates.

{¶ 25} Upon review of One Power's motion to dismiss, the Commission denies this request. Contrary to One Power's contentions, the Company's application did not propose an increase in rates pursuant to R.C. 4909.18. Furthermore, we note that the Company's proposal should not impact customer rates, but rather require heightened commitments prior to interconnection and service. Considering that this proceeding is one of first impression for this Commission and the state of Ohio, all procedural steps taken in this case have been made publicly, in addition to being covered by several media outlets. The public interest in this case is further evidenced by the robust list of intervening parties and comments filed in the docket. Also, this proceeding does not involve a request to increase rates for existing customers because the proposed tariff involves the emergence of a prominent, new type of customer. Thus, we deny One Power's motion to dismiss.

2. OMAEG's Requests to Overturn ALJs' Rulings

{¶ 26} In its briefed arguments, OMAEG asserts that the Commission should overturn the ALJ's ruling limiting cross-examination of AEP Ohio witness Ali. OMAEG claims that the ALJ hindered a full review and examination of potential alternative solutions to the problem that AEP Ohio claims to exist or claims will exist in the future. According to

OMAEG, since Mr. Ali did not provide his transmission planning models in his pre-filed testimony, OMAEG wanted to determine whether the new generation resources currently being constructed in central Ohio were considered in the model. By proffer, OMAEG alleges that, had it been allowed to further cross-examine Mr. Ali, it would have examined his credibility and underlying modeling assumptions (Tr. Vol. I at 216-217). OMAEG claims that the ALJ's ruling was, thus, unsupported and inconsistent with the requirements of R.C. 4903.09, and requests that the Commission reverse the ruling. (OMAEG Initial Br. at 13-14.)

{¶ 27} In reply, AEP Ohio disputes that the ALJ's ruling deprived OMAEG of due process rights. Here, the Company believes that the ALJ correctly determined that Mr. Ali's testimony already addressed whether any existing regional transmission organization (RTO)-controlled generational resources and prospective projects were included in modeling the Company's capacity constraints. The Company notes that the ALJ's decision to stop OMAEG's counsel from asking about specific generation projects did not prohibit OMAEG's counsel from asking further questions about the credibility and underlying assumptions of Mr. Ali's modeling, as well as questions regarding technologies, other voltage issues, AEP Ohio's proposed solution, and alternative transmission solutions other than constructing a 765 kV line or implementing the proposed tariffs. (AEP Ohio Reply Br. at 64-65.)

{¶ 28} OMAEG's current request for the Commission to reverse the ALJ's ruling has no bearing on the points that OMAEG purports it was trying to make during the cross-examination of Mr. Ali. The ALJ allowed OMAEG's counsel to ask about specific RTO-controlled transmission projects in the AEP Ohio service territory until Mr. Ali indicated that he was not able to answer without consulting his models or at least a transmission map. In the interest of administrative efficiency and clarity for the record, the ALJ properly stopped OMAEG's counsel from continuing to ask AEP Ohio witness Ali whether or not he was aware of an extensive list of generation projects in AEP Ohio's service territory. We note that Mr. Ali had indicated that he was not aware at the time of questioning whether specific projects were factored into his models or not. (Tr. Vol. I at 212-14.) We also find that the actual line of questioning that transpired has no bearing on the due process concerns OMAEG raises, given how the ALJ ruled.

{¶ 29} OMAEG also takes issue with the ALJs' ruling that limited cross-examination of AEP Ohio's witness McKenzie regarding a non-admitted document. By proffer, OMAEG represents that throughout his testimonies and cross-examination, Mr. McKenzie discussed the economic concerns AEP Ohio considered when developing its proposed schedule, whether additional capacity exists on the current transmission system, transmission planning, the economics of data centers, and economic development in Ohio, all of which are material to this case (Tr. VIII at 1645-1647). OMAEG believes that its cross-examination on these matters elicited information demonstrating the contradictory nature of Mr. McKenzie's testimony, including the fact that, despite having instituted a moratorium on data centers in central Ohio, the Company is allegedly encouraging them to locate in the Company's service territory. OMAEG accordingly concludes that such contradictory testimony impacts Mr. McKenzie's credibility as a witness, while AEP Ohio's contradictory actions speak to the Company's good faith, or lack thereof, in initiating this case. OMAEG opines that the ALJ ruled that OMAEG could not continue this line of questioning without providing sufficient explanation as required by R.C. 4903.09. OMAEG thus states that the ruling resulted in the exclusion of facts and evidence relevant and material to this case, causing prejudice to OMAEG and other parties, and that the Commission should reverse the ALJs' ruling. (OMAEG Initial Br. at 15-16.)

{¶ 30} In reply, AEP Ohio contends that OMAEG's arguments regarding Mr. McKenzie's cross-examination fail on the grounds of foundation and relevance. AEP Ohio notes that during hearing, Mr. McKenzie repeatedly testified that he was unfamiliar with the document OMAEG attempted to examine him about, and that he was seeing it for the first time (Tr. Vol. VIII at 1622, 1630-31, 1633-35, 1641). Further, AEP Ohio believes that the relevance of the document and OMAEG's questions based on the document are also questionable, since this involves circumstances in 2017, which took place before the events leading to the initiation of this proceeding. Moreover, the Company points out that

OMAEG's counsel was permitted latitude in asking about the document it presented during hearing. AEP Ohio, thus, requests that the ALJs' ruling be maintained. (AEP Reply Br. at 66-68.)

{¶ 31} The Commission affirms the ALJs' ruling on the exclusion of OMAEG's exhibit from the evidentiary record as well as the limiting of cross-examination of Mr. McKenzie based on a document he had never previously reviewed. We recognize that Mr. McKenzie testified several times that he had never seen the document that OMAEG introduced as OMAEG Ex. 26 (Tr. Vol. VIII at 1622, 1630-31, 1633-35, 1641). Moreover, the ALJ entertained several responses from parties regarding whether Mr. McKenzie could authenticate the exhibit in question and whether he could answer questions about its substance. During this line of questioning, the ALJ placed reasonable parameters on OMAEG's counsel which would allow counsel to ask about the document's substance while balancing the concern that Mr. McKenzie was not familiar with the document. As such, the ALJ properly directed OMAEG's counsel to continue their questioning up to the point where Mr. McKenzie would not know any specifics or information about the document. (Tr. Vol. VIII at 1629). However, the cross-examination developed to a point where OMAEG's counsel continued to deviate from the ruling regarding the document and the ALJ, utilizing the discretion afforded in the Commission's administrative rules, ended the line of questioning. (Tr. Vol. VIII at 1645). The Commission finds the ALJ's decision on this issue to be reasonable and emphasizes that OMAEG was given significant leeway to ask questions about the substance contained in the document with the specific instruction to not read the document into the record. Thus, the Commission affirms the ALJ's ruling.

3. Motions for Protective order

a. OBC's Motion

{¶ 32} On August 30, 2024, OBC filed a motion for a protective order and memorandum in support, requesting prohibiting the public disclosure of trade secret information which includes confidential, commercially, and competitively sensitive information related to the association's members contained within Attachment SR-7 to witness Robertson's testimony filed on August 29, 2024. OBC also notes that in an abundance of caution, it redacted the name and contact information of AEP Ohio's customer service representative from the attachment. In its memorandum in support, OBC discusses that the confidential information pertains to an email exchange between AEP Ohio personnel and OBC witness Robertson, disclosure of which could irreparably harm or risk one of OBC's members. No memorandum contra were filed.

{¶ 33} On November 12, 2024, OMAEG filed a motion for protective order and memorandum in support requesting that the Commission prohibit the public disclosure of confidential and proprietary information in OMAEG's workpapers attached as Supplemental Attachment JS-2 of the Supplementary Testimony of John Seryak in the docket. Specifically, OMAEG asserts that Mr. Seryak's workpapers, containing data and analyses compilations, have been afforded confidential protection during discovery and were provided to the Company pursuant to a protective agreement. No memoranda contra were filed.

{¶ 34} On October 31, 2024, AEP Ohio filed a motion for protective agreement regarding information contained in Witness McKenzie's supplemental testimony (AEP Ex. 3), as requested by OMAEG. In its filing, the Company noted that it was not consenting or otherwise agreeing that the information is confidential or proprietary under Ohio law or is deserving protective treatment, but out of abundance of caution, the Company redacted certain provisions per OMAEG's request. Relatedly on December 3, 2024, OMAEG filed its own motion for protective treatment regarding AEP Ohio witness McKenzie's testimony, OMAEG's governance and management, and membership. OMAEG's motion alleged that information regarding associations' membership lists have been previously considered protected information. No party disputes OMAEG's motion.[2]

{¶ 35} R.C. 4905.07 provides that all facts and information in the possession of the Commission shall be public, except as provided in R.C. 149.43 and as consistent with the purposes of Title 49 of the Revised Code. R.C. 149.43 specifies that the term "public records" excludes information which, under state or federal law, may not be released. The Ohio Supreme Court has clarified that the "state or federal law" exemption is intended to cover trade secrets. *State ex rel. Besser v. Ohio State*, 89 Ohio St. 396, 399 (2000).

{¶ 36} Similarly, Ohio Adm.Code 4901-1-24 allows the Commission to issue an order to protect the confidentiality of information contained in a filed document, "to the extent that state or federal law prohibits release of the information, including where the information is deemed * * * to constitute a trade secret under Ohio law, and where nondisclosure of the information is not inconsistent with the purposes of Title 49 of the Revised Code."

{¶ 37} Ohio law defines a trade secret as:

> information * * * that satisfies both of the following: (1) It derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. (2) It is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

R.C. 1333.61(D)

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2 In response to OMAEG's motion for protective agreement, AEP Ohio filed a memorandum contra on December 6, 2024. However, OMAEG and AEP Ohio resolved their dispute regarding the redacting of certain portions of Mr. McKenzie's supplemental testimony in opposition to the 10/10 Stipulation (AEP Ex. 3). The Commission finds that OMAEG's request supersedes the Company's motion for protective order regarding this matter.

{¶ 38} The Commission has reviewed the arguments presented, and the information included in the motions for protective treatment. Applying the requirements that the information have independent economic value and be the subject of reasonable efforts to maintain its secrecy pursuant to R. C. 1333.61(D), as well as the six-factor test set forth by the Ohio Supreme Court,[3] the Commission finds the information subject to the motions for protective order constitute trade secrets and, therefore, their release is prohibited under state law.

{¶ 39} Ohio Adm.Code 4901-1-24(F) provides that, unless otherwise ordered, protective orders issued pursuant to Ohio Adm.Code 4901-1-24(D) automatically expire after 24 months. Therefore, confidential treatment shall be afforded for a period ending 24 months from the date of this Order (i.e., July 9, 2027). Until that date, the Docketing Division should continue to maintain, under seal, the information addressed in this motion.

{¶ 40} Ohio Adm.Code 4901-1-24(F), requires a party wishing to extend a protective order to file an appropriate motion at least 45 days in advance of the expiration date. If OBC or OMAEG wishes to extend this confidential treatment, they should file an appropriate motion in respect to the protected information within 45 days in advance of the expiration date. If no such motions to extend confidential treatment are filed, the Commission may release this information without prior notice to the parties.

III. APPLICATION AND STIPULATIONS

A. *Summary of the Application*

{¶ 41} In the application, AEP Ohio seeks to establish two new tariffs pursuant to R.C. 4909.18, the Data Center Power tariff and the Mobile Data Center tariff, due to its

3 *See State ex rel. The Plain Dealer v. Ohio Dept. of Ins.*, 80 Ohio St.3d 513, 524-525 (1997).

observation of exponential load growth demand from data centers[4] in recent years. The Company explains that it is not looking for a general base rate increase but instead wishes to create two new customer classifications that appropriately reflect the unique load requirements of the data centers and mobile data centers requesting to reserve capacity. Moreover, the Company clarifies that data center and cryptocurrency mining customers that have signed service agreements with the Company prior to the proposed tariffs being effective will continue to be served under the Company's existing General Service tariffs. (AEP Ex. 1 at 1.)

{¶ 42} In support of its request, AEP Ohio indicates that it has signed letters of agreements (LOAs) or electric service agreements (ESAs) with data center customers that will more than double the amount of load in central Ohio by 2030. According to the Company, there have been over 50 customers at approximately 90 sites who have submitted requests to reserve capacity for new or expanded load (that have not yet executed contracts) totaling more than 30,000 MW. Further, AEP Ohio emphasizes that there is no longer PJM Interconnection, LLC (PJM) regional transmission organization (RTO)-controlled generation in central Ohio. Instead, central Ohio's load is served by imported power through a robust 765 kilovolt (kV) transmission network. Accordingly, it is the Company's position that significant transmission investments will be required to continue to provide safe and reliable electricity to the existing customers and customers with signed agreements for service commencing in the near future. As such, the Company believes that these new tariffs would help with operational demands and planning challenges posed by data center customers. Specifically, AEP Ohio represents that the proposed tariffs include a long-term capacity commitment to ensure the load capacity expansion is aligned with data center customers' demand and to help justify the time and cost associated with the buildout of required transmission to serve these unique customers. (AEP Ex. 1 at 1-2, 4-5.)

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[4] When this Order refers to "data center(s)"it includes "mobile data centers" as defined in the 10/23 Stipulation, discussed later in this Order.

{¶ 43} The application further highlights that data centers are distinguished from commercial or industrial businesses because they require a high level of demand—operating 24 hours, seven days a week for 365 days per year with no natural cycling —and often have load factors (the ratio of actual consumption and maxium possible consumption) that exceed 95-percent. Furthermore, the Company stresses that some data centers may lack physically affixed structures, which implies that these customers could easily relocate without much stranded investment on their side of the meter. And lastly, AEP Ohio represents in its application that, while data centers (and mobile data centers) can generate economic development, they are often less impactful than the economic development generated by other commercial and industrial customers. (AEP Ex. 1 at 3-4.)

{¶ 44} Under the proposed tariffs in the application, customers would be required to meet a minimum billing demand threshold, starting at 90 percent of minimum contract demand. Other provisions include an exit fee to end the contract early, collateral and security provisions to address instances of bankruptcy or avoidance of payment, and required participation in the PJM Emergency Demand Response program or AEP Ohio-declared emergency event. Additional provisions address customer mobility, system reliability, and compliance with technical standards. The proposed tariffs would also include a separate Standard Service Offer (SSO) auction for the new data center customer classes. (AEP Ex. 1 at 8-10.)

{¶ 45} Lastly, the application notifies the Commission that since March 2023, the Company implemented a temporary moratorium on taking new service requests in central Ohio from data center customers and executing service agreements. The application explains that this moratorium was implemented to give AEP Ohio's Transmission Planning group time to study the data center load requests' impact on the electrical delivery system in central Ohio. Another aspect of this temporary pause involved the Company creating a "first come, first served" queue whereby prospective data center customers looking to expand their existing services or new prospective data center customers looking to locate in the AEP Ohio service territory could submit their requests for service (without signing any agreements) that would be addressed by the Company in due course. In its application, AEP Ohio states that there are currently over 50 customers in that queue that comprise the anticipated 30,000 MW of load demand. The Company, therefore, insists that this pause status needs to be continued while its tariff application remains pending and until the solution is implemented to move forward. Lastly, the Company represents that it met with and communicated the need for the moratorium with all prospective data center customers that submitted requests for service. (AEP Ex. 1 at 6-7.)

B. *Summary of the Stipulations*

{¶ 46} As noted above, subsequent to the Company filing its application on May 31, 2024, and the filing of initial and reply comments, two competing stipulations were submitted on October 10, 2024 and October 23, 2024. The following is a summary of the conditions agreed to by signatories to the 10/10 Stipulation and 10/23 Stipulation, in a comparative format, and is not intended to replace or supersede the actual terms of the stipulations.

10/10 Stipulation	**10/23 Stipulation**
Signatories ADS, Constellation, OELC, OMAEG, Enchanted Rock, DCC, RESA, Blockchain, Google, Sidecat, OBC, Microsoft, One Power, and IGS	*Signatories* AEP Ohio, OEG, Walmart, OPAE, OCC, and Staff
Application The 10/10 Stipulation signatories recommend that the Commission adopt the Company's application as modified by this stipulation.	
Tariff Applicability Schedule Electricity-Intensive Customer (EIC) would apply to any ESA signed after the tariff effective date for a new load	*Tariff Applicability* Schedule Data Center Tariff (DCT) would apply to any data center customer ESA signed after the tariff effective date for a

greater than 50 MW at a single location so long as AEP Ohio provides proof of a transmission capacity constraint for that site. Schedule EIC would not be limited in its application to specific customer types, industries, businesses or operational profiles.	new load (or expansion of an existing load) greater in the aggregate than 25 MW.
Grandfathered Loads Schedule EIC would not apply to loads greater than 50 MW at a single location that has already signed an LOA or ESA by the effective date of the new tariff.	*Grandfathered Loads* Loads above 25 MW that have already signed an LOA or ESA by the effective date of the tariff are "grandfathered", so long as the load does not expand by more than 25 MW above contracted capacity under the existing ESA following the effective date of Schedule DCT. Schedule DCT will apply to a grandfathered load that signs a new ESA to expand its load by more than 25 MW above contracted capacity under the existing ESA after the effective date of the tariff. At the customer's request, AEP Ohio will use reasonable efforts to separately meter the new (non-grandfathered) load to which Schedule DCT applies but it may not be technically feasible to do so. If the load is not separately metered, then the grandfathered load will lose its grandfathering status and become subject to Schedule DCT. Schedule DCT customers are not eligible to participate in AEP Ohio's 1 coincident peak (1CP) or 6CP Basic Transmission Cost Rider (BTCR) programs or any successor programs (subject to same grandfathering as current participation outlined above.)
Load Ramp Period The "load ramp period" will commence upon energization and will not exceed four years, and the capacity used for	*Load Ramp Period* The "load ramp period" will not exceed four years and the contract capacity will be no less than:

determining minimum monthly billing demand will be no less than: Year 1: 30-percent of Contract Capacity Year 2: 50-percent of Contract Capacity Year 3: 70-percent of Contract Capacity Year 4: 90-percent of Contract Capacity	In Year 1: 50-percent contract capacity In Year 2: 65-percent contract capacity In Year 3: 80-percent contract capacity In Year 4: 90-percent contract capacity
Contract Term Term A: Term of the ESA will equal the load ramp period (no greater than four years) plus 8 years, with an option to exit after Year 5, with a 1-year exit fee. Term B: Term of the ESA will equal the load ramp period plus 10 years, with an option to exit after Year 7, with no exit fee. Term C: Term of the ESA will equal the load ramp period plus 12 years, with an option to exit after Year 9, with no exit fee.	*Contract Term* The initial term of the contract will equal the Load Ramp Period (no greater than four years) plus eight years. If regional transmission upgrades are needed, the in-service date estimate will be high-level and contingent on numerous factors outside of AEP Ohio's control. If electric infrastructure is not in place to serve the customer by the estimated in-service date, the customer may petition the Commission for an adjustment to the contract term based on the facts and circumstances presented at the time (but the contract term will otherwise remain the load ramp period plus eight years).
Collateral All customers with a contract capacity of less than 75 MW for a single location would remain subject to the existing GS tariff (or successor tariff) security/collateral requirements. All customers with a 75 MW or more capacity for a single location would be subject to the security/collateral requirements proposed in the Company's application if the customer does not have either (a) a credit rating of at least A- from S&P Global Inc. (S&P) and A3 from Moody's Corporation (Moody's)or (b) cash and cash equivalents on an audited balance sheet prepared in accordance with Generally Accepted Accounting Principles	*Collateral* Collateral and other tariff requirements will remain the same, as requested in the Company's application (which would require data center customers who have credit ratings less than A- from S&P, A3 from Moody's to provide a parent guarantee or collateral in the form of a letter of credit or cash equal to 50 percent of the customer's minimum charges under the ESA. The collateral amount would be calculated based on AEP Ohio's rates at the time the ESA is signed).

greater than ten times the collateral requirement.	
Minimum Demand Charges Monthly billing demand would be no less than the greater of: a) a maximum minimum demand corresponding to the term length (A-C) the customer selects; or b) a percentage of the customer's contract capacity according to the following schedule: for customers with **50,001 kilowatt (kW) to 75,000 kW** of total contract capacity, minimum demand is 32,500 kW plus 85 percent of marginal amount over 50,000 kW; or **more than 75,001 kW** of total contract capacity, minimum demand is 53,750 kW plus 100 percent of marginal amount over 75,000 kW; however, the minimum demand will not exceed 85 percent of total contract capacity for Term A customers, 80 percent for Term B customers, and 75 percent for Term C customers).	*Minimum Demand Charges* Monthly billing demand would be no less than the greater of: a) 85-percent of the customer's highest previously established monthly billing demand during the past 11 months; or b) percentage of the customer's contract capacity according to the following schedule: for customers with **25,001 kW to 75,000 kW** of total contract capacity: minimum demand is 15,000 kW plus 85 percent of any capacity above 25,000 kW; or **with more than 75,000 kW** of total contract capacity, minimum demand is 57,500 kW plus 100 percent of any capacity above 75,000 kW. However, the minimum demand cannot exceed 85 percent of the total contract capacity. With Commission approval, service may be suspended by AEP Ohio if customer usage exceeds its contract capacity by more than 1,000 kW. If additional capacity is available from AEP Ohio to serve additional load at the customer's site, the Company may also seek mutual agreement to adjust the contract capacity and reserves the right to raise the issue before the Commission if there is no agreement.
Assigning Retail Capacity to Another Customer If a customer wishes to reduce its contract capacity under Schedule EIC during the term of the ESA, it may request that AEP	*Assigning Retail Capacity to Another Customer* If a customer wishes to reduce its contract capacity under Schedule DCT during the term of the contract, it may request that

Ohio assign up to 50 percent of its contract capacity to another Schedule EIC customer in lieu of continuing minimum demand charges for that reallocated capacity and/or paying some or all of its exit fee. If a successful assignment is made, the assigning customer would be relieved of its contractual obligations going forward relating to the assigned load. Consistent with any applicable legal or regulatory requirements, AEP Ohio will make a good faith effort to accommodate capacity assignments.	AEP Ohio assign up to 25 percent of its contract capacity to another Schedule DCT customer in lieu of paying some or all of its exit fee associated with the reallocated capacity. If a successful assignment is made, the assigning customer would be relieved of its contractual obligations going forward relating to the reallocated capacity and shall continue to be responsible for any remaining unused contract capacity. The assigning customer cannot sign up for replacement capacity until a reasonable period after assigning capacity passes or circumstances demonstrably change. Consistent with any applicable legal or regulatory requirements, AEP Ohio will make a good faith effort to accommodate this request so long as all the following conditions are met: 1) The receiving customer signs an ESA for the reallocated capacity under Schedule DCT; 2) AEP Ohio determines that the transfer is electrically feasible; 3) The receiving customer pays for all equipment and any other incremental costs required to transfer the reallocated capacity; 4) The receiving customer satisfies all collateral requirements under Schedule DCT; 5) Transferring the reallocated capacity would not result in any stranded investment being recovered from other ratepayers (or, if it would, the assigning customer pays for the full cost of the stranded equipment); and 6) Both parties attest in writing to AEP Ohio that no money or other

	compensation beyond covering the cost items listed above in this paragraph is exchanged or provided as consideration for the reallocated capacity .
	Aggregation All new loads of affiliated companies and companies with common ownership will be considered in the aggregate for purposes of calculating the minimum demand charge. If there are multiple new facilities at a single location of less than 25 MW, but the aggregate total load is greater than 25 MW, all of those facilities will be subject to Schedule DCT.
Signing Up New Customers Until Schedule EIC becomes effective and implemented, prospective large load customers will remain in the Company's queue unless the customer load can be served by the existing transmission system capacity. The following process applies to a new facility served under Schedule EIC: 1) Customer will request a load study from the Company and pay a one-time fee of $10k within 120 days or forfeit spot. 2) AEP Ohio will conduct the load study and determine a service plan for the customer. AEP Ohio will make reasonable efforts to complete the load study within (i) 60 days if regional transmission upgrades are needed to serve the customer or (ii) 45 days (for all other situations). 3) Once the customer and AEP Ohio agree to the terms of an LOA and ESA, the customer will have 90 days	*Signing Up New Customers* Until Schedule DCT is approved, the Company's moratorium will be in place and customers will remain in the queue. The following process applies to a new facility or expansion of an existing facility under Schedule DCT: 1) Customer may request a load study from the Company, so long as it controls the property (own, lease or have an option) and provide a specific location, load ramp, and final load. AEP Ohio will charge a one-time fee for each load study from $10k to $100k to be paid within 45 days or customers will forfeit their spot. 2) AEP Ohio will conduct the load study and determine a service plan for each customer in the AEP Ohio central Ohio queue that timely paid the load study fee. The Company will try to prioritize customers on a "first come, first served" basis and

to sign off and approve. Any buildout costs and Contribution in Aid of Construction (CIAC) will be addressed through an LOA consistent with AEP Ohio's then-existing tariff provisions that apply to all customers. AEP Ohio will also present the customer an ESA under the Schedule EIC tariff that will include a good faith estimate of the energization date of service, but if regional transmission upgrades are needed, the in-service date estimate will be high-level and contingent on numerous factors outside of AEP Ohio's control. The ESA contract capacity during the load ramp period will be set at zero MW and only become effective upon energization. Customers will have to demonstrate control over the property (e.g. own, lease or have an option) before contracts are executed. If electric infrastructure is not in place to serve the customer by the estimated in-service date in the ESA, the end date of the ESA will not change, and contract capacity for the load ramp period will remain at 0 MW until AEP Ohio has demonstrated that the customer can be served by available transmission facilities and the customer is energized.	will make reasonable efforts to complete a load study within (i) 60 days if regional transmission upgrades are needed to serve the customer; or (ii) 45 days (for all other situations). If regional transmission upgrades are necessary before AEP Ohio can serve the customer, AEP Ohio will group customers from the queue into tranches based on the expected capacity increase associated with each regional upgrade project. 3) AEP Ohio will provide an LOA and ESA for signature. The LOA requires customers to reimburse AEP Ohio 100 percent of the buildout costs if the customer cancels or delays the project by more than 12 months prior to target energization date. Once the project is completed, the LOA obligation will expire. The ESA would include a good faith estimate of energization date of service. 4) Customer will have 60 days to sign the LOA and ESA. AEP Ohio will include the Schedule DCT customer's load in its PJM forecast, and the necessary transmission infrastructure, if any, to serve the customer will be constructed pursuant to the PJM transmission planning process. Once all infrastructure is in place to begin service, AEP Ohio will energize the customer and the contract will begin.
	Opportunity for Contract Capacity Reduction AEP Ohio shall communicate a one-time opportunity to Schedule GS customers whose contract demand exceeds 25 MW the

	opportunity to reduce their existing contract capacity provided: (1) doing so does not create a stranded asset related to plant-in-service that was installed to serve the customer's larger load request, and (2) the customer agrees not to request additional capacity at that location for three years after the reduction absent a demonstrated change in circumstances.
Behind-The-Meter Generation Customers may interconnect behind-the-meter (BTM) generation and/or co-located load on the same terms and under the applicable interconnection rules, as any other customer, including any applicable new regulation or future rule changes. AEP Ohio's language in the section titled Customer-Owned Generation and Emergency Conditions will not be included in any schedule. The minimum demand calculation will allow netting to include consideration of the customer's firm commitments to reduce load with BTM generation.	*Behind-The-Meter Generation* To ensure that the customer's election to net does not result in it exceeding its contract capacity, equipment must be in place and maintained through the term of the ESA to instantaneously curtail load equal to or greater than the BTM generation output, subject to the then-current technical requirements of the transmission provider. If the BTM generation equipment fails and results in the customer exceeding its contract capacity, the Company reserves the right to raise before the Commission any unresolved reliability or safety concerns based on the facts and circumstances presented at that time.
Exit Fee and Minimum Demand Charge Revenue All exit fee and minimum demand charge revenue collected by AEP Ohio under Schedule EIC shall be credited to the Company's BTCR revenue requirement or deferred as a regulatory liability with a carrying charge at AEP Ohio's weighted average cost of capital.	*Exit Fees* The application's exit fee provisions should be adopted, with the following modifications. Data centers will be eligible to pay the applicable exit fee after the completion of five years of the contract, excluding load ramp period, meaning if there is a load ramp period of three years, the customer may exit after year eight (three year load ramp period and five years of contract). AEP Ohio will create a regulatory liability, with carrying costs at the Company's weighted average cost of capital, for any exit fee revenue or any revenue collected

	from customer collateral. Within six months of receiving such exit fee revenue (including through the conversion of collateral/security), AEP Ohio will advance a proposal for Commission approval to flow the funds back to the benefit of its retail customers over the remaining term of the contract of the data center customer that paid the exit fee or posted the collateral.
SSO Customers served under Schedule EIC and all other customers having an existing ESA with contract capacity over 25 MW that are part of the 5,000 MW expansion currently under ESA will not be eligible to return to the existing default SSO auction product. Instead, the customers that fall under these tariff requirements and those that have an existing ESA with contract capacity over 25 MW will be served by a separate yet-to-be-determined competitive and transparent process where competitive suppliers, subject to qualifying criteria approved by the Commission, will provide electric power and energy that is based on real time energy and a pass-through of capacity plus an adder for ancillary costs and the supplier's cost.	*SSO* The application's SSO provisions were withdrawn from consideration.
Public Posting cf Contract Forms AEP Ohio shall post the standard contract and form applications and contracts it uses for all primary and transmission customers (whether served under Schedule EIC or otherwise) on a publicly available website. These publicly available forms shall comply with the terms of AEP Ohio's Commission-approved tariffs. Further, AEP Ohio shall post its standard Schedule	

EIC contracting process on a publicly available website.	
Emergency Interruption Customers taking service under Schedule EIC may be interrupted during grid emergencies under the same circumstances as any other customer, including any applicable new regulation or future rule changes.	
Contract Renewal Following the conclusion of an ESA under Schedule EIC, a customer would be served under the terms of AEP Ohio's existing Schedule GS tariff or any successor tariff.	
MDC/FLT Tariff The Company's proposed Schedule MDC/FLT in its application will be eliminated, without prejudice.	
Initiation of Commission-Ordered Investigation The signatories request that the Commission initiate a Commission-ordered investigation (COI) that will evaluate opportunities that could positively impact near-term transmission capacity constraint issues on AEP Ohio's system.	

Jt. Ex. 1 at 3-15; Jt. Ex. 2 at 2-11 (emphasis added).

IV. DISCUSSION

A. Consideration of the Stipulations

{¶ 47} Ohio Adm.Code 4901-1-30 authorizes parties to Commission proceedings to enter into stipulations. Although not binding upon the Commission, the terms of such an agreement are accorded substantial weight. *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, 125 (1992), citing *Akron v. Pub. Util. Comm.*, 55 Ohio St.2d 155, 157 (1978). This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties and resolves all issues presented in the proceeding in which it is offered.

{¶ 48} The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Dominion Retail v. Dayton Power and Light*, Case No. 03-2405-EL-CSS, et al., Opinion and Order (Feb. 2, 2005); *In re Cincinnati Gas & Elec. Co.*, Case No. 91-410-EL-AIR, Order on Remand (Apr. 14, 1994); *In re W. Reserve Telephone Co.*, Case No. 93-230-TP-ALT, Opinion and Order (Mar. 30, 1994); *In re Cleveland Elec. Illum. Co.*, Case No. 88-170-EL-AIR, et al., Opinion and Order (Jan. 31, 1989); *In re Restatement of Accounts and Records*, Case No. 84-1187-EL-UNC, Opinion and Order (Nov. 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of the stipulations at issue, the Commission has used the following criteria.

1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

2) Does the settlement, as a package, benefit ratepayers and the public interest?

3) Does the settlement package violate any important regulatory principle or practice?

{¶ 49} The Supreme Court of Ohio has endorsed the Commission's analysis using these criteria to resolve cases in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co.*, 68 Ohio St.3d 559, citing *Consumers' Counsel* at 126. Each of the signatory parties urge the Commission to approve their respective stipulations, in their entirety. The Commission addresses the parties' specific arguments in the context of the three criteria for evaluating the reasonableness of the stipulations below.

{¶ 50} The Commission further notes that many of the parties' arguments overlap to an extent where some points may apply under more than one prong of the Commission's test. Accordingly, the Commission has analyzed such arguments under the prong deemed most appropriate. Additionally, to the extent an argument made by any party that purports to be relevant to the three-prong test is not discussed in its entirety, the Commission has nevertheless given the argument full and careful consideration, and such argument has been rejected.

{¶ 51} The Commission also recognizes that this case presents novel circumstances where two opposing stipulations were submitted for Commission consideration. Here, we note that our evaluation of the settlements shall be consistent within the three-prong test. However, ultimately, such a review lends itself to this Commission determining which one of the two settlements satisfies the three-prong test, and thus offers the most advantageous provisions for utility ratepayers while advancing the policies set forth in R.C. 4928.02.

1. IS THE STIPULATION THE PRODUCT OF SERIOUS BARGAINING AMONG CAPABLE, KNOWLEDGEABLE PARTIES?

a. The 10/10 Stipulation

{¶ 52} AEP Ohio argues that, in contrast with the 10/23 Stipulation, the 10/10 Stipulation was not the result of serious bargaining among knowledgeable, capable parties. First, AEP Ohio asserts that the 10/10 Stipulation was the product of a private, compressed process among a subset of intervening parties, with no open or transparent process among all parties. In support of this point, AEP Ohio states that it was unaware of a group of parties pursuing a separate agreement until the afternoon of October 7, 2024, when counsel for ADS circulated a new term sheet and indicated that a full draft stipulation would be circulated the next day. ADS counsel circulated the referenced full stipulation on October 8, 2024, along with an indication that he would request signatures the following day. ADS counsel then circulated a "final review version" on October 9, 2024, asked for those desiring the join the stipulation to sign off, and stated that the executed stipulation would be filed on October 10, 2024. AEP Ohio insists that this 43-hour window between notification and circulating a "final review version" was unduly compressed and did not allow for the type of open, all-party discussions that had been held over the previous month. (AEP Ex. 3 at 9.) Further, AEP Ohio believes that any modifications made to the October 8, 2024 term sheet were never explained or attributed to any party, and, thus, were not the result of open discussions or bargaining amongst the parties. AEP Ohio believes that the negotiations that led to the 10/10 Stipulation were based on a separate, private process where intervening parties held bilateral discussions between a subset of parties. (AEP Initial Br. at 28.)

{¶ 53} Second, AEP Ohio also argues that the 10/10 Stipulation overwhelmingly promotes the interests of data center customers at the expense of other manufacturing, industrial, and residential customers. Whereas the 10/23 Stipulation recommends a data center tariff imposing financial obligations only on data centers, AEP Ohio states that the 10/10 Stipulation's proposed tariff would subject all customers to heightened financial obligations. Based on this, the Company questions why OMAEG and OELC, which AEP Ohio asserts represent manufacturing and industrial customers, would join such an agreement. AEP Ohio speculates as to the true motives of OMAEG and OELC and raises "concerns" as to whether serious negotiation occurred among the 10/10 Stipulation parties. (AEP Ex. 3 at 14.) Based on their support of the 10/10 Stipulation, AEP Ohio argues that OMAEG should be viewed as merely another data center-aligned party. Overall, AEP Ohio insists that the 10/10 Stipulation was not the product of serious bargaining among knowledgeable, capable parties simply because it overwhelmingly reflects and advances likeminded data center interests. Likewise, OEG stresses that the signatory parties to the 10/10 Stipulation include data centers, cryptominers, CRES providers, behind the meter (BTM) solution providers, and larger user groups, all of whose interests are "complementary" and at the expense of other industries (OEG Ex. 1 at 4). Walmart does not take a definitive stance as to whether the 10/10 Stipulation satisfies the first prong, but echoes the points raised by OEG as to the similarity of interests among the 10/10 Stipulation parties. Walmart, therefore, suggests that the Commission should define the meaning of "serious bargaining" in the three-part test. (AEP Ohio Br. at 28-33; OEG Initial Br. at 5; Walmart Br. at 5-6.)

{¶ 54} Third, AEP Ohio characterizes the 10/10 Stipulation as a "faux settlement" that is not the product of serious bargaining because it unilaterally imposes multiple commitments on the Company without consideration, bargaining, or the Company's consent. Thus, according to the Company, no quid pro quo exists for these commitments, and to adopt such a flawed settlement would violate basic contract principles of Ohio law. Because the signatories to the 10/10 Stipulation are a limited subset of intervenors, without the utility applicant, AEP Ohio avers that the 10/10 Stipulation fails to truly settle any of the issues raised in the application. Therefore, AEP Ohio argues that the 10/10 Stipulation fails to satisfy the criteria necessary to constitute a stipulation under Ohio Adm.Code 4901-1-30. AEP Ohio also asserts that adopting a stipulation entered into solely among intervenors would be bad public policy, as it would undermine the very purposes of settlements in Commission proceedings, which is intended to resolve disputes between a utility and stakeholders. (AEP Ohio Br. 33-37.)

{¶ 55} The 10/10 Stipulation parties disagree with the Company's characterization of the 10/10 Stipulation and assert that it is a product of serious bargaining among knowledgeable parties. The 10/10 Stipulation parties agree with AEP Ohio's outline of the settlement discussion timeline and concurs with the Company's assessment that all parties were afforded the opportunity to attend and fully participate in the seven all-party settlement meetings that occurred in September. DCC states that the bilateral and multilateral discussions between parties that took place following the seventh all-party settlement meeting were merely continuations of the conversations over the previous month. ADS asserts that AEP Ohio and OEG cannot credibly deny that the 10/10 Stipulation parties worked from the same term sheets and the same discussions as all other parties in this case. In support of this contention, ADS highlights that the terms sheet that its counsel circulated on October 7, 2024, was based on, and proposed modifications to, the most-recent draft term sheet sent by AEP Ohio to the parties (ADS Ex. 4). Further, the email communications that sent the term sheet and draft stipulation noted that all parties were welcome to send comments or edits and that some parties had already done so (ADS Ex. 5). Google, RESA, IGS, One Power, OMAEG, OBC, and Constellation agree with this sentiment, stating that the all-party settlement meetings organized by AEP Ohio formed the basis of the 10/10 Stipulation and was not a completely separate process, as claimed by the Company. Since all parties were included in the settlement discussions, Google submits that Commission precedent would deem this serious bargaining. DCC, ADS, and IGS also find it significant that the 10/10 Stipulation was joined by a majority of the intervenors in this case, representing diverse interests. OELC agrees with and adopts the arguments raised by the other 10/10 Stipulation parties on this issue, and states that the 10/10 Stipulation is the product of serious bargaining. ADS, RESA, OBC, One Power, and IGS also note that Staff, while a signatory to the 10/23 Stipulation, agrees that the 10/10 Stipulation was the product of serious bargaining by capable and knowledgeable parties (Staff Ex. 1 at 46-47). (Google Initial Br. at 11-13; ADS Initial Br. at 17-18; RESA Br. at 9-10; IGS Br. at 5-6; One Power Initial Br. at 30-31; OMAEG Initial Br. at 19-22; OBC Initial Br. at 14-16; OELC Initial Br. at 3; ADS Reply Br. at 6-7.)

{¶ 56} Moreover, in response to AEP Ohio's contention that the 10/10 Stipulation overwhelmingly supports the interests of data center customers over other customer classes, ADS notes that the 10/10 Stipulation is supported not only by data center customers, but also by blockchain/crypto customers, CRES providers, trade associations, generation and technology service providers, and consumers groups representing a swath of commercial and industrial energy customers. ADS states that these parties have both overlapping and competing interests but collaborated to arrive at a workable solution. Google echoes this sentiment, stating that the 10/10 Stipulation parties are a diverse group representing a variety of unique perspectives in the energy industry. Multiple other intervening parties also highlight the diversity of interests of the different parties to the 10/10 Stipulation. (ADS Reply Br. at 8-9; Google Reply Br. at 5; OBC Reply Br. at 7; DCC Initial Br. at 22; OMAEG Initial Br. at 18-19.)

{¶ 57} 10/10 Stipulation signatories find AEP Ohio's questioning of OMAEG and OELC's motives in joining the 10/10 Stipulation to be completely baseless. DCC avers that neither witness McKenzie nor AEP Ohio is in a better position than OMAEG itself to determine what is in the best interests of the organization and its members. OMAEG and OELC similarly echo the sentiment that they, themselves and not the Company, are in the best position to determine whether or not to support a stipulation. OELC directly responds to the criticisms of AEP Ohio witness McKenzie. According to OELC, the sole basis for AEP Ohio's claim that OELC is not a capable, knowledgeable party is witness McKenzie's cursory assessment (AEP Ex. 3 at 15-16). OELC states that Mr. McKenzie has no personal knowledge of OELC's reasons for its legal strategy or its posture in this proceeding. Accordingly, OELC urges the Commission to give no weight to Mr. McKenzie's testimony on this issue. (DCC Reply Br. at 19-20; OMAEG Reply Br. at 16; OELC Initial Br. at 4-6.)

{¶ 58} With respect to AEP Ohio's "faux settlement" arguments, ADS highlights that only AEP Ohio and OEG have questioned whether the 10/10 Stipulation satisfies the first prong. ADS, OBC, OMAEG, and One Power all point to the testimony of Staff witness Healey, who testified that no party should have veto power over a stipulation and that Staff does not dispute that the 10/10 Stipulation was the product of serious bargaining (Staff Ex. 1 at 46, Tr. Vol. XII at 2534, 2537.) Further, ADS asserts that there is no requirement in Commission precedent that a settlement include the utility. ADS distinguishes this proceeding from the South Carolina Public Service Commission case cited by AEP Ohio in its initial brief.[5] (ADS Initial Br. at 18-19; OBC Initial Br. at 13; OMAEG Initial Br. at 19; One Power Initial Br. at 30.)

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5 *Daufuskie Island Util. Co., v. South Carolina Office of Regulatory Staff*, 420 S.C. 305, 314-316 (2017).

b. The 10/23 Stipulation

{¶ 59} AEP Ohio argues that the 10/23 Stipulation is the product of serious bargaining among capable, knowledgeable parties, whereas the 10/10 Stipulation fails to meet this prong. AEP Ohio points to the history of settlement discussions in this proceeding, noting that the Company initiated the all-party settlement process on September 4, 2024, and then proceeded to hold six additional all-party meetings before the 10/10 Stipulation was filed. AEP Ohio witness McKenzie testified that all parties were invited to the seven all-party settlement meetings and that all were given the opportunity to raise any questions or concerns regarding the application. The Company states that it continued all-party settlement discussions after the filing of the 10/10 Stipulation, inviting all parties – including 10/10 Stipulation signatory parties – to participate in further settlement discussions on October 16, October 18, and October 22, 2024. Further, AEP Ohio states that term sheets and counterproposals were circulated by both the Company and multiple intervening parties – AEP Ohio circulated four proposed settlement term sheets prior to October 1, while DCC, OEG, OMAEG, Constellation, and Enchanted Rock participated in the circulation of term sheets over this same period. Finally, AEP Ohio asserts that it is undisputed that all signatory parties to the 10/23 Stipulation have vast experience in Commission proceedings and were represented by seasoned counsel. (AEP Ex. 3 at 8, 10.) In sum, AEP Ohio contends that it led an all-inclusive and transparent settlement process that included all parties and afforded each party the opportunity to engage in serious negotiation. The other 10/23 Stipulation parties generally echo the points raised by AEP Ohio on this prong and agree that the 10/23 Stipulation satisfies this criterion. (AEP Ohio Br. at 23-25; Staff Initial Br. at 10; OEG Initial Br. at 4-6; OCC/OPAE Initial Br. at 18.)

{¶ 60} In turn, some 10/10 Stipulation parties argue that the 10/23 Stipulation does not satisfy this first prong. DCC concedes that parties to the 10/23 Stipulation are capable and knowledgeable but asserts that the makeup of those signatory parties causes the stipulation to fail the first prong. DCC states that parties to the 10/23 Stipulation represent a minority of parties in the case and do not include any data center customers. DCC argues that not including a single party representing the customers that will be subject to the new tariff is a sign that serious bargaining did not occur. Further, DCC avers that the moratorium instituted by AEP Ohio on new data center customers weakened the ability of data center customers to bargain fairly and seriously with the Company. OMAEG also raises its concerns as to whether the 10/23 Stipulation was seriously bargained for. OMAEG believes that AEP Ohio withheld pertinent information concerning its transmission system and its interaction with affiliate companies; has undisclosed financial reasons for the proposals in the application and 10/23 Stipulation; has engaged in coercive actions via the moratorium; and simply lacks knowledge about its own transmission systems. OMAEG believes that all of these concerns indicate that the 10/23 Stipulation was not the product of serious bargaining. OBC endorses the issues raised by OMAEG, arguing that such conduct on AEP Ohio's end is not a part of serious bargaining. Enchanted Rock does not dispute that either stipulation was the product of serious bargaining but asserts that the unprecedented situation of two stipulations filed in the same case is the cause of disagreement over this usually, uncontroversial prong in Commission proceedings. However, Enchanted Rock states that the filing of two competing stipulations does not indicate that either or both were not seriously bargained. (DCC Initial Br. at 55-56; OMAEG Initial Br. at 25-29; OBC Initial Br. at 28-29; Enchanted Rock Br. at 8.)

c. Conclusion

{¶ 61} Having reviewed the record in this proceeding, and evaluated the arguments of all parties, the Commission concludes that both the 10/10 Stipulation and the 10/23 Stipulation were the product of serious bargaining among capable, knowledgeable parties. As an initial point, the Commission endorses the testimony of Staff witness Healey, in which he stated that no party has veto power over a stipulation, be it Staff, a regulated utility, or any other stakeholder (Tr. Vol. XII, 2534). Thus, the arguments made by parties to both stipulations that the lack of the utility or a particular group of customer as a signatory on a stipulation invalidates the entire settlement goes too far and is inconsistent with precedent. The makeup of parties to a stipulation is a factor that the Commission may consider in evaluating a stipulation, but it is not controlling of the determination of this prong of the analysis. See, e.g., *In re Ohio Edison Co., The Cleveland Elec. Illum. Co., and The Toledo Edison Co.*, Case No. 13-2173-EL-RDR, et al., Opinion and Order (Dec. 1, 2021) at ¶ 66.

{¶ 62} The Commission considers a party capable and knowledgeable for the purposes of part one of the three-part test if that party is familiar with Commission processes, regulatory matters, and the specific terms of the stipulation at issue. *See In re Duke Energy Ohio, Inc,* Case Nos. 21-887-EL-AIR, et al., Opinion and Order at ¶ 100 (Dec. 14, 2022); *In re The East Ohio Gas Company d/b/a Dominion Energy Ohio*, Case No. 19-468-GA-ALT (*Dominion Alt. Case*), Opinion and Order (Dec. 30, 2020) at ¶ 44. The Commission has long held that the focus is on each party being afforded the opportunity to participate in settlement discussions and a determination as to whether a particular class of customers was excluded from involvement. *In re Ohio Power Co.*, Case No. 17-1230-EL-UNC, Opinion and Order (Feb. 27, 2019) at ¶ 27 citing *Time Warner Axis v. Pub. Util. Comm.*, 75 Ohio St.3d 229, 233 (1996). Furthermore, beyond the Commission's longstanding determination that no party has veto power over a stipulation, we find that no percentage of parties or specific quantity of stipulation signatories will determine whether the first prong is met. We reiterate that the determination of the first prong in this analysis is case-by-case.

{¶ 63} While the level of involvement may have varied among parties in this proceeding, there is ample evidence in the record that all parties were given the opportunity to participate in settlement discussions via the all-party meetings, the circulation of term sheets, and additional communications that took place among subsets of parties and their counsel (AEP Ex. 3 at 8, 10). As outlined extensively by AEP Ohio, the Company initiated all-party settlement discussions in September 2024, and held seven all-party settlement meetings between September 4, 2024, and the filing of the first stipulation on October 10, 2024. Further, between September 4 and October 1, 2024, the Company circulated four different proposed term sheets to all parties. (AEP Ex. 3 at 8.) DCC, OEG, OMAEG, Constellation, and Enchanted Rock also circulated term sheets throughout this period of settlement discussions (DCC Ex. 4; AEP Ex. 3 at 8; AEP Ex. 4 at 4). As AEP Ohio witness

McKenzie testified, at the all-party settlement meetings each party was permitted to speak and provide its perspective on the Company's application (AEP Ex. 3 at 8). Parties from both stipulations engaged in additional bilateral and multilateral communications among various parties during the settlement process and following the seventh all-party meeting (Tr. Vol. V at 854-55). AEP Ohio's argument that the formulation and execution of the 10/10 Stipulation was a completely separate process—without any connection to the previous all-party settlement discussions, circulated term sheets, phone calls, and email communications—is unpersuasive and is contradicted by the evidence in this case. ADS demonstrated, and AEP Ohio witness McKenzie confirmed, that the term sheet which ADS counsel circulated on October 7 included a document that was redlined against the most-recent draft term sheet circulated by AEP Ohio. (ADS Ex. 4; Tr. Vol. V at 804-805; Tr. Vol. VI at 1171-1173.) Much of the conflict over this first prong appears to stem primarily from the unusual situation presented to the Commission – the filing of two competing stipulations. We agree, however, with Enchanted Rock that two rival stipulations do not indicate that either, or both, were not the result of serious bargaining. Clearly the 10/10 Stipulation deviated from AEP Ohio's proposal and what became the 10/23 Stipulation, but both settlements originated from the same process.

{¶ 64} AEP Ohio's contention that the 10/10 Stipulation is not the product of serious bargaining because it overwhelmingly favors data center interests at the expense of other industries is equally unconvincing. It is to be expected that parties will join settlements that they deem the most beneficial to themselves or their members. This, however, does not mean that such a settlement is not the result of serious bargaining. One need only review the comments filed in this case docket by numerous parties, which show that some of their initial positions/proposals were altered in negotiating the terms of the 10/10 Stipulation (*See* ADS Initial Comments; DCC Initial Comments; Google Initial Comments; OMAEG Initial Comments; Constellation Initial Comments; OBC Initial Comments; RESA Initial Comments; Enchanted Rock Initial Comments; One Power Initial Comments; OELC Initial Comments all filed on June 25, 2024.) Likewise, AEP Ohio's questioning of the motives of various parties for entering into the 10/10 Stipulation are purely speculative. The Commission finds that attacks on attorneys' knowledge and capabilities appear to be based on little more than assumptions that do not hold weight in this proceeding. This Commission has previously held that parties themselves are in the best position to evaluate their best interests, and we assume that parties will negotiate in support of their own interests. *Dominion Alt. Case,* Opinion and Order (Dec. 30, 2020) at ¶ 44. Therefore, each party is in the best position to determine if signing a stipulation is in its best interests.

{¶ 65} For largely the same reasons outlined above in Paragraph 61, the Commission also rejects the arguments from DCC, OMAEG, and OBC that the 10/23 Stipulation is not the product of serious bargaining. The presence, or non-presence, of a particular party or group of parties is not controlling. Just as the presence or absence of the utility on the 10/10 Stipulation does not trigger failure of prong one, whether or not data centers joined the 10/23 Stipulation does not automatically show a lack of serious bargaining. Moreover, the argument that no data center customers signed the 10/23 Stipulation is not persuasive on the merits of the first prong. Parties had a choice to sign onto the 10/10 Stipulation or the 10/23 Stipulation. We are not going to weigh other parties' participation in the earlier stipulation against the 10/23 Stipulation in terms of signatory diversity. Moreover, both stipulations have an assortment of parties that are capable of making the decisions they determine are in their best interest. OMAEG's questioning the "undisclosed motivations" of AEP Ohio in negotiating the 10/23 Stipulation is the same type of behavior that OMAEG decried when the Company questioned its motives in joining the 10/10 Stipulation (OMAEG Initial Br. at 25). To the extent that OMAEG and OBC truly believed that relevant discoverable material was not being provided by AEP Ohio, it should have raised the matter with the ALJs during the discovery process rather than wait to make the claim in briefs.

2. DOES THE STIPULATION, AS A PACKAGE, BENEFIT RATEPAYERS AND THE PUBLIC INTEREST?

a. The 10/10 Stipulation

{¶ 66} Signatories of the 10/10 Stipulation generally represent that this stipulation strikes a more balanced approach compared to the original provisions in the application and those proposed in the 10/23 Stipulation. These parties thus represent that this stipulation, as a package, benefits ratepayers and the public interest because it is better tailored for the issues identified by AEP Ohio and does not discriminate against a specific industry. Notably, some parties emphasize that the 10/10 Stipulation addresses the issues presented in AEP Ohio's application without facilitating a regulatory environment that could discourage data center investors in Ohio.

i. ECONOMIC DEVELOPMENT

{¶ 67} Proponents of the 10/10 Stipulation assert that their stipulation furthers state policies enumerated in R.C. 4928.02, which includes facilitating the state's effectiveness in the global economy. Trade associations, OBC and OELC, indicate that the data center industry has become integral in the global economy and has become instrumental to the State of Ohio's economy. ADS and Google also highlight that data centers have proven to be very beneficial to the State of Ohio's economy. OELC asserts that not only are data centers integral to the economy in this age, but they have also been pivotal in establishing Ohio as a leading technology hub (OMAEG Ex. 26 at 21). Further, OBC cites to a 2022 report from the Bureau of Economic Analysis, which states that the U.S.' digital economy contributed $3.7 trillion to gross output, $2.41 trillion in value added —10.3-percent of Gross Domestic Product (GDP) — and supported eight-million jobs in 2021, in which data centers were vital to these contributions (Google Ex. 1 at 4). (OBC Initial Br. at 17-18; OELC Initial Br. at 7.)

{¶ 68} Relatedly, on a statewide basis, ADS notes that AEP Ohio witness Ali confirmed that data centers were a positive economic sign for the state (Tr. Vol. II at 454-455). ADS further highlights that AEP Ohio witness McKenzie testified that the Company wants to attract data center customers to their service territory. ADS confirms that it has developed data centers in Franklin, Licking, and Union counties in central Ohio, and notes that from 2015 to 2023, its parent company, AWS, has invested $10.3 billion in Ohio in both capital and operating expenditures with over $1 billion being invested in new data center campuses currently being built (ADS Ex. 8 at 7). Further, ADS proclaims that it has supported an estimated 4,760 indirect, full-time equivalent jobs and contributed $3.8-billion to Ohio's total GDP. Moreover, ADS witness Fradette testified that AWS intends to invest an additional $7.8-billion by 2030 to expand its data center operations in Ohio and has been touted as the second-largest single private sector company investment in Ohio's entire history (*Id*). Relatedly, Google reports that since 2019, it has invested over $6.7-billion in data centers across central Ohio. Google also emphasizes that it has created more than 1,000 direct jobs in the state, with over 850 positions related to the data centers' operations. Furthermore, Google indicates that in 2023, it generated $14.02 billion in economic activity for "thousands of businesses, publishers, nonprofits, creators, and developers across Ohio" (Google Ex. 1 at 5). OBC also indicates that its member, 500 N 4th Street LLC d/b/a Standard Power (Standard Power), has invested at least $60 million on capital investments, research and development, and job training in the state. And according to OBC, Standard Power projects that its pending expansion plans and partnerships could result in the creation of 200-300 new jobs and several billion dollars of advanced technology capital expenditures over the next three years (OBC Ex. 7 at 7-8). (ADS Initial Br. at 9-10; Google Initial Br. at 4-5; OBC Initial Br. at 18.)

{¶ 69} On the other hand, AEP Ohio asserts that the 10/10 Stipulation directly violates R.C. 4928.02 by significantly hindering economic development and Ohio's competitiveness in the global economy. AEP Ohio's service territory currently enjoys notable competitive advantages over other regions of the country when it comes to attracting data centers, including access to high-quality power from extra-high voltage (EHV) transmission, abundant water, a well-educated workforce, flat land, and a mild climate – all of which will persist even if the 10/10 Stipulation is adopted. However, the Company believes that the broad application of the 10/10 Stipulation's Schedule EIC requirements to all large loads could negatively impact Ohio's ability to attract the "job-creating" manufacturing and industrial facilities. Staff adds that economic development from data centers must be reasonably balanced with accountability for the costs that they create. While Staff clarifies that it takes no position as to the specific calculations offered by 10/10 Stipulation signatories in support of their arguments, Staff believes that data centers can have positive benefits for the Ohio economy, especially during construction. Moreover, Staff insists that it has consistently voiced that it wants data centers to have a clear path to locate in central Ohio. On this point, OEG highlights that AEP Ohio recognizes the value that data centers bring to the state's economy, given how it has spent many years actively recruiting such customers to locate in Ohio. However, Staff and other 10/23 Stipulation signatories believe that the interests of non-data centers must also be considered, and there must be reasonable accountability for the data centers as the cost causers for the anticipated transmission build out. (AEP Ohio Br. at 84; AEP Ohio Reply Br. at 34; Staff Reply Br. at 21; OEG Initial Br. at 28.)

ii. Tailored to Transmission Constraints

{¶ 70} Proponents of the 10/10 Stipulation argue that this agreement specifically targets the transmission constraint issues raised in the Company's application. DCC asserts that the 10/10 Stipulation is a targeted, durable solution that addresses the challenge of AEP Ohio's rapid load growth in transmission-constrained areas. Moreover, DCC insists that the fundamental issue is not only a "data centers in central Ohio challenge." Signatories, thus, point out that the 10/10 Stipulation ensures that, when a non-data center energy intensive customer requires the Company to build more transmission, the Company will not have to return to the Commission for another proceeding to mitigate transmission capacity risks for other non-cost causing customers. As such, One Power argues that the 10/10 Stipulation narrowly tailors the solution to the problem, rather than the 10/23 Stipulation which does not solve the alleged load growth and transmission constraint issue. In support, One Power notes that the proof of transmission capacity will ensure that there will be verified proof of such issues before increased financial obligations apply to Schedule EIC members. OMAEG and OBC assert that the constraint proof provision ensures that only the customers that trigger a need for the expanded transmission capacity will solely bear the burden of paying for it (Tr. Vol. IX at 1950-1951). Enchanted Rock also notes that the proof of transmission capacity constraint is crucial before subjecting intensive energy users to stricter operating requirements related to transmission constraints and infrastructure expansion. OMAEG and OBC add that the proof of constraint provision promotes grid reliability by encouraging large load customers to locate at places with available capacity. OBC indicates that Schedule EIC's applicability to large load customers will incentivize those customers to move elsewhere and, therefore, strain the grid less (OMAEG Ex. 36 at 16-17; OBC Ex. 9 at 14). (DCC Initial Br. at 26; One Power Initial Br. at 33; OMAEG Initial Br. at 37- 38; OBC Initial Br. at 19; Enchanted Rock Br. at 16.)

{¶ 71} AEP Ohio disputes the general call from 10/10 Stipulation signatories for further proof of transmission constraints. The Company insists that the record overwhelmingly demonstrates that new and expanding data center customers are driving the need for substantial transmission investments in central Ohio. The Company opines that if not addressed, the transmission constraints will impact the broad stability and reliability of the entire grid (Tr. Vol. I at 65-66, 184). Moreover, AEP Ohio insists that it is new and expanding data center customers that are driving exponential growth throughout the Company's service territory and not traditional manufacturing or other large load customers. AEP Ohio insists that the 10/10 Stipulation signatory parties do not dispute AEP Ohio witness Ali's testimony regarding the existing peak demand in central Ohio and anticipated increase in load by 2030. Even some 10/10 Stipulation witnesses acknowledge the exponential load growth currently being experienced in AEP Ohio's service territory is primarily driven by data centers (citing to Tr. Vol. IX at 2036-2037, cross-examination of

DCC witness Higgins, agreeing that data center load is driving much of the increase in demand in AEP Ohio's service territory). AEP Ohio further explains that the record clearly shows that substantial transmission investments will have to be made to address the data center-driven load growth because there is no regional transmission organization (RTO)-controlled generation currently located within central Ohio, so all electricity is imported through the transmission network (Tr. Vol. I at 171, 210-211). Furthermore, the AEP Ohio Transmission Planning organization ran a series of studies to determine what system limits would occur, and such studies demonstrate that even an additional 1,500 MW above 10,000 MW of load will result in numerous overload and voltage violations throughout the central Ohio region (Sidecat Ex. 10). While AEP Ohio admits that it will need to work with PJM to identify the full extent of overload issues both within the Company's footprint and any other regional issues associated with serving large load additions in central Ohio, the Company expects that, in order to alleviate these issues, a solution requiring the construction of a large EHV line into the central Ohio region may be necessary at 1,500 MW over 10,000 MW and three 765 kV lines will be needed at 4,500 MW over 10,000 MW (AEP Ex. 2 at 8-10; Sidecat Ex. 10; Tr. Vol. II at 394-395). Company witness McKenzie explained that nearly all transmission voltage level data center customers, particularly those whose load exceeds 50 MW, will require some level of transmission investment (Tr. Vol. V at 938-939; AEP Ex. 3 at 27-29). (AEP Ohio Br. at 41-43)

{¶ 72} AEP Ohio accordingly argues that the 10/10 Stipulation's proof of transmission constraint provision is unnecessary and unworkable and would negatively impact the Company's ability to manage the grid in an efficient and effective manner. According to the Company, this requirement would suspend prudent utility management actions and result in inappropriate micromanagement of the grid, which would be extremely inefficient and time-consuming. AEP Ohio indicates that this provision of the 10/10 Stipulation lacks a clear standard and is ambiguous regarding what constitutes a "significant" investment, the "study" which is required, and what "proof" AEP Ohio would need to provide customers. AEP Ohio points out that not even the 10/10 Stipulation signatories appear to understand how this provision would be applied, as DCC witness Higgins admitted that "there's some room for judgment and interpretation there" regarding the definition of 'study' (Tr. Vol. IX at 2078-2079). This ambiguity would only increase the potential for misunderstandings and disputes that would further undermine cooperation between customers and the Company, and hinder AEP Ohio's ability to effectively manage the grid. The Company also believes that these terms would have a negative impact on economic development, as these vague requirements would cloud a customer's ability to accurately evaluate the rates they will be charged should they choose to locate within Ohio (Tr. Vol. V at 941-942). Furthermore, AEP Ohio opines that the transmission capacity constraint requirements fail to account for the interconnectedness of the transmission system. The Company explains that because the system is integrated and interconnected, an issue in one area can often spread to all other areas of the grid (Tr. Vol. I at 66). (AEP Ohio Br. at 69-71.)

{¶ 73} In response, One Power insists that the 10/10 Stipulation's transmission constraint language is necessary, reasonable, and entirely workable; and AEP Ohio is more than capable of complying with this requirement in-house. One Power points out that with its resistance to prove transmission constraints, the Company ignores the fact that data centers could easily locate outside of central Ohio, outside of AEP Ohio's service territory, that is. OMAEG adds that the Company's resistance to a proof of constraint provision is meritless because such a requirement should be an implicit requirement for the Company, should it determine that it cannot provide timely electric service to a customer. (One Power Reply Br. at 25-26; OMAEG Reply Br. at 30.)

{¶ 74} Relatedly, Constellation and Enchanted Rock attest that the 10/10 Stipulation's BTM and co-located generation provisions offer a tailored solution to AEP Ohio's transmission constraint concerns. Constellation witness Hutchinson testified that co-located load and BTM generation promotes more efficient interconnection of large loads to the grid by reducing the distance needed to transmit the new load, which mitigates the risk of overloading transmission lines and minimizes transmission line losses (Constellation Ex.

12 at 10-11). As a result, BTM and co-located generation can also avoid the need for system upgrades to serve new large loads. Moreover, both Constellation and Enchanted Rock emphasize that the use of BTM and/or co-located generation will assist with the lag in service for a new customer and the building of infrastructure expansion, as those resources can provide data centers with reliable electricity until the grid can provide an adequate supply. (Constellation Br. at 14-15; Enchanted Rock Br. at 10-11.) On the contrary, OEG expresses some skepticism over the proposed BTM provisions in the 10/10 Stipulation. OEG believes that the proposed language is more ambiguous and problematic if the BTM generation does not reduce transmission usage. OEG, thus, asserts that if the BTM generation is not used to reduce a customer's transmission, then its billing demand should not be reduced as a result. (OEG Initial Br. at 17.)

iii. Mitigates Risk of Stranded Costs

{¶ 75} The 10/10 Stipulation signatories also represent that the stipulation's terms mitigate the risk of stranded costs. Notably, DCC asserts that the minimum demand provision in the 10/10 Stipulation provides a floor minimum of guaranteed revenues back to AEP Ohio. Per the 10/10 Stipulation, customers with contract capacities between 50 and 75 MW would pay an effective demand no lower than 65 percent and as high as 71.66 percent, and customers with contract capacities greater than 75 MW would result in even higher guaranteed revenues to AEP Ohio. Under DCC witness Higgins' quantitative analysis and cost assumptions, if 6,407 MW of incremental data center load were subjected to eight-year minimum contracts with a 60 percent minimum demand charge, based on current BTCR rates, the associated minimum revenue recovered from these customers would net a present value of $2.097 billion over eight years. DCC therefore points out that the incremental revenue is considerably greater than the 40-year net present value of the total expected incremental revenue requirement from construction of the new line ($1.2 billion) (DCC Ex. 9 at 25). DCC thus concludes that under a reasonable set of assumptions, the 60 percent minimum demand charge over eight years would provide more than sufficient revenue coverage for a new EHV transmission facility. DCC insists that witness

Higgins' analysis demonstrates that, while the Company may incur incremental costs to serve new loads, these loads would bring incremental billing determinants and new revenues that will recover the incremental costs invested for the new transmission lines and contribute to recovery of AEP Ohio's current (embedded) transmission costs (DCC Ex. 9 at 25-26). DCC also indicates that the 10/10 Stipulation offers further protections to customers by adding contract term requirements to the end of the load ramp period, rather than having a load ramp subsumed within the 10-year contract term. DCC overall believes that witness Higgins has clearly demonstrated that the minimum contract term, exit fee, and minimum demand charge provisions in the 10/10 Stipulation comfortably cover a reasonable, conservative estimate of the Company's incremental transmission costs associated with serving data center load. DCC thus concludes that it is the guaranteed minimum revenues under the 10/10 Stipulation that mitigate the risk of stranded cost borne by non-data center customers. Relatedly, Google points out that AEP Ohio will receive additional revenue under Term B and Term C of the 10/10 Stipulation and, therefore, an exit fee is not necessary for those two contract terms (Google Reply Br. at 8). ADS also emphasizes that its witness Fradette testified that incentivizing greater flexibility on minimum demand and exit conditions in return for longer contract periods allow the Company to minimize the risk of stranded transmission costs, while still allowing for decreases in a customer's demand due to a variety of reasons, including BTM generation. Relatedly, Enchanted Rock emphasizes that the commitment to utilize BTM generation will mitigate stranded investment risk, as the asset risk is kept with the asset owner and not imposed on ratepayers (DCC Initial Br. at 28- 33; AWS Br. at 12; Enchanted Rock Br. at 10).

{¶ 76} AEP Ohio disputes that the 10/10 Stipulation mitigates the risk of stranded costs. Specifically, the Company takes issue with the 10/10 Stipulation's resizing contract capacity provisions. The Company highlights that it is important to ensure that any capacity reduction by an existing customer does not result in stranded costs that would add a financial burden to other customers. The Company reiterates that it will need to invest in its transmission system to service anticipated data center loads. As a result, under the 10/10

Stipulation, where a customer may wish to reduce its contract capacity, AEP Ohio believes that such a reduction would result in underutilized transmission assets, the costs of which will be shifted to other customers (Tr. Vol. VIII at 1600-1601). (AEP Ohio Br. at 63.)

{¶ 77} The Company also opines that Mr. Higgins' study fails to account for a number of critical factors that would have a material impact on his conclusions. First, AEP Ohio believes that Mr. Higgins has evaluated the merits of the 10/10 Stipulation under the "best case" circumstances, disregarding the practical reality that data center customers may be contributing less revenue over a shorter period than he assumes. Further, Mr. Higgins' analysis does not account for any potential changes in BTCR rates associated with increased load within AEP Ohio's service territory, instead assuming a constant value over a period of up to 15 years (Tr. Vol. IX at 2048). Witness Higgins also did not consider the Federal Energy Regulatory Commission (FERC)-jurisdictional process for assigning revenue requirements to load serving entities, which further impacts the Company's recovery of transmission costs. AEP Ohio indicates that the most critical flaw is that DCC's analysis only focuses on a single solution without also considering that new large load may require more than just the construction of new EHV lines (*Id.* at 2050). AEP Ohio highlights that Mr. Higgins admitted that he only considered the need for one 765 KV line and that if AEP Ohio witness Ali's estimate of three lines would be needed, Mr. Higgins testified that it would result in a different analysis number (*Id.* at 2126- 2127). Lastly, AEP Ohio states that another critical flaw is that Mr. Higgins' analysis incorporates numerous assumptions regarding factors that have the potential to vary greatly based on the unique circumstances surrounding each transmission investment made by AEP Ohio, including the appropriate recovery period for the transmission investment, the overall transmission revenue requirement, the amount of load that will be served by the transmission investment, and the exact contributions that will be made by data center customers (*Id.* at 2050-2051). AEP Ohio therefore concludes that Mr. Higgins' analysis is incomplete and is misleading in favor of DCC's own interests. (AEP Ohio Reply Br. at 31-34.)

{¶ 78} 10/23 Stipulation signatories further opine that the 10/10 Stipulation could result in instances of leaving non-cost causers with unwarranted stranded costs. Walmart generally argues that the 10/10 Stipulation focuses too much on facilitating the growth of data centers and cryptocurrency and too little on protecting existing customers. Walmart emphasizes that existing customers need reasonable assurance that any new customers triggering the need for significant transmission investments will pay their fair share and bear the risk of potential foregone cost recovery. Furthermore, Walmart explains that costs of transmission investments are typically recovered over multiple decades. However, under the 10/10 Stipulation, existing customers could be stuck with the majority of costs incurred to serve data centers because the proposed provisions protect datacenters more than existing customers (i.e. can terminate contracts after only a few years). Relatedly, OEG takes issue that only one of three contract length options include an exit fee, and a data center could terminate its contract without an exit fee in as little as seven years. OEG insists that these are significant shortcomings in the 10/10 Stipulation (OEG Ex. 1 at 5, 9, 10). Jointly, OCC and OPAE also express concern that the 10/10 Stipulation's lower ramp up percentage does not properly protect all customers (Staff Ex. 1 at 49). OCC and OPAE assert that the lower ramp-up percentage will force non-data center customer classes to pay for the significant gap in data centers' contract capacity during the ramp-up period. Jointly, OCC and OPAE opine that such provisions would result in greater stranded costs shifted away from the cost causer and onto other customer classes who would receive zero benefits (OCC Ex. 2 at 7; Staff Ex. 1 at 49). (Walmart Br. at 6-8; OEG Initial Br. at 11, 15; OCC/OPAE Initial Br. at 26-27.)

iv. Measures for More Efficiency and Transparency

{¶ 79} 10/10 Stipulation signatories also maintain that this stipulation facilitates more efficiency in enrolling new customers and identifying further solutions for AEP Ohio's constraint issues. One Power attests that the 10/10 Stipulation establishes a more detailed, transparent and efficient process for new customers. One Power witness Kent testified that his experience with securing new service with AEP Ohio has been frustrating for companies looking to make significant capital investments in the State of Ohio (One Power Ex. 5 at 9). One Power represents that the Company requires contracts with new customers that do not receive Commission review and are unauthorized by its tariffs, which means that the Company can improperly change such form contracts by whim. OMAEG also expresses concerns that AEP Ohio allegedly admitted that it does not have a way to separate committed data center customers from speculative ones (OMAEG Ex. 36 at 19). One Power, thus, advocates for the 10/10 Stipulation because it requires public disclosure of the form documents used for primary and transmission voltage customers, including the Company's load study applications, CIAC agreements, LOAs, new service applications, ramp-up agreements, ESAs, and other form documents. One Power witness Kent stresses that the 10/10 Stipulation's process provisions would make the standard sign-up and contract process more efficient, transparent, and customer-friendly (One Power Ex. 5 at 10). Google also avers that the posting of all of this information will greatly improve customers' comprehension of the Company's process and reduce both disputes with the Company and delays in the new or expanded service process. (One Power Initial Br. at 34-35; Google Initial Br. at 23; OMAEG Initial Br. at 38-39.)

{¶ 80} In reply, AEP Ohio notes that both the 10/23 Stipulation and 10/10 Stipulation contain provisions regarding the sign-up process for new data center customers; however, the Company expresses concerns that the 10/10 Stipulation lacks key provisions necessary to protect the interests of AEP Ohio's existing customers and to ensure effective grid management. Particularly, the Company takes issue with the 10/10 Stipulation's load study fee because it is unreasonably low and fails to reflect and account for the actual costs incurred by AEP Ohio in conducting load studies for larger, more complex data center loads (AEP Ex. 4 at 26-27). AEP Ohio also finds the requirement for customers to make reasonable efforts to control the land where their facility would be located is not an adequate commitment. AEP Ohio insists that nothing less than requiring actual control of the facility site opens the door for a data center to prematurely submit their request for a load study. Furthermore, the Company declares that the 10/10 Stipulation provisions regarding the customer sign-up process sets forth excessive and unnecessarily long timeframes for customers that would delay the interconnection process and frustrate the Company's ability to manage new requests. Next, the Company takes issue with the 10/10 Stipulation's limit of customer liability under the LOA to an amount equal to the CIAC. If adopted, AEP Ohio insists that this approach would represent a major departure from AEP Ohio's standard practice, which requires sufficient collateral so that the customer can repay the Company for the cost of all local investments caused by the customer, which is significantly more than what would be covered under by the CIAC (AEP Ex. 3 at 39). The Company explains that by maintaining its practices to offset the cost of stranded investments, the Company's standard LOA protects other customers from unfair increases in rates. (AEP Ohio Br. at 60-62.)

{¶ 81} The Company also believes that public posting of contract forms would limit AEP Ohio's ability to customize ESAs to meet the specific requirements of each customer, which may result in less effective agreements and will increase AEP Ohio's costs. The Company argues that this requirement would also discourage AEP Ohio from making timely modifications to agreements which would stagnate contract evolution and hinder its ability to adapt to changing market conditions and customer needs. (AEP Ex. 3 at 35-36.) AEP Ohio further indicates that mandatory public posting may confuse potential customers and lead to disputes that detract from the clarity and efficiency. Moreover, the disclosure could necessitate revealing confidential customer information which AEP Ohio is bound to protect, adversely impacting economic development and the competitive landscape (Tr. Vol. VIII at 1587). (AEP Ohio Br. at 71-72.)

{¶ 82} 10/10 Stipulation signatories further distinguish that this settlement offers more efficiency and transparency than the 10/23 Stipulation because it recommends that the Commission initiate a COI. Google indicates that a COI would give the Commission a unique opportunity to evaluate technological advances and alternatives that could assist utilities with extracting more value from the existing interconnection system/grid at a lower cost and faster timeline. Google posits that the traditional focus on capital investments and associated return in usual utility ratemaking can discourage lower costs or operational expenditures that may avoid or defer the need for costly infrastructure upgrades (Google Ex. 1 at 22). According to Google, this kind of prioritization disincentivizes utilities from exploring more cost effective solutions, without the COI. Further, OMAEG emphasizes that a COI would evaluate opportunities that could positively impact areas such as utility data transparency, operational efficiencies, reconductoring and market-driven opportunities such as battery storage, surplus interconnection of distribution-level generation and storage, virtual power plants, and grid-enhancing technologies from both utility and market-driven opportunities. (Google Initial Br. at 25-26; OMAEG Initial Br. at 37.)

{¶ 83} In response, AEP Ohio avers that the recommended COI overlaps with issues already being addressed by existing Commission cases and processes, including AEP Ohio's base rate cases, electric security plan (ESP) cases, and regular Commission rule review processes (AEP Ex. 3 at 44-45). The Company also raises that the Commission bears the burden of proof when opening a COI under R.C. 4905.26, and reasonable grounds have not been met to open such an investigation. Moreover, AEP Ohio believes that the proposed COI implicates jurisdictional issues; and asking the Commission to investigate various transmission planning opportunities risks an overlap of issues solely governed under FERC jurisdiction. (AEP Initial Br. at 76-77.)

{¶ 84} During this proceeding, RESA also raises concerns over an alleged lack of transparency from AEP Ohio regarding the extraordinary load growth associated with data centers. RESA points out that the Company's Long Term Forecast Report (LTFR) filed in March 2023 projected almost zero load growth. However, March of 2023 was also the month that the Company implemented its moratorium on signing service agreements with additional data centers in central Ohio due to the magnitude of data center load under contract and the additional date centers requesting new service. Furthermore, RESA notes that one month before this case was initiated in April 2024, AEP Ohio filed its 2024 LTFR, which did not account for projected load growth anywhere near the ones included in this case. And RESA continues to point out that the Company has been actively trying to enter into BTM competitive generation supply arrangements with data center customers in central Ohio, citing to *In re Ohio Power Co.*, Case No. 25-133-EL-AEC; *In re Ohio Power Co.*, Case No. 25-134-EL-AEC. As a result, RESA alleges that asymmetric access to information deprives the market from responding to needs and is antithetical to Ohio's pro-market energy policies, corporate separation requirements, and statutory antitrust provisions. Furthermore, RESA indicates that this case's record does not address the extent to which the Company's lack of transparency benefitted AEP Ohio's other lines of business. Yet, RESA alleges that the record does show that the Company is actively engaged in having its regulated service employees refer business to its competitive market affiliates (OBC Ex. 7 Attach. SR-7 at 208). As a result, RESA insists that the Commission should adopt the 10/10 Stipulation's recommendation to initiate a COI. (RESA Br. at 16-19.)

{¶ 85} Regarding RESA's allegations, AEP Ohio insists that it has appropriately avoided reporting overly speculative load that could lead to overinvestment in the transmission system. AEP Ohio emphasizes that it has consistently reported critical load growth relevant to the transmission system as part of the PJM planning process and in its LTFR filed with the Commission. (AEP Ohio Reply Br. at 41.)

v. SSO Provisions

{¶ 86} IGS, RESA, and Constellation also endorse the 10/10 Stipulation's proposed SSO provisions. Constellation points out that in the case of AEP Ohio's slice-of-system procurement structure for its SSO all classes of customers must pay for the risk of serving data centers' different load curve. (Constellation Ex. 4 at 11.) Constellation further opines that in the past, SSO prices have been much lower than the market price, which would put pressure on SSO suppliers to purchase additional hedges or risk paying for additional energy for the unanticipated load from large customers migrating back to the SSO. Such an event drives up SSO prices for all customers. Constellation insists that the 10/10 Stipulation addresses the above concerns by establishing a competitive and transparent process for the provision of SSO to customers on Schedule EIC and all other existing customers that have an ESA with a contract capacity over 25 MW. According to Constellation, the process proposed in the 10/10 Stipulation should generate sufficient SSO supplier interest to provide a competitive product for large load customers. Constellation represents that energy pass-through products like the one proposed by the 10/10 Stipulation have been shown to work in other PJM states. Constellation declares that this process "would provide the best, efficient and cost-effective means to ensure that the supply [for large load customers] is procured competitively" (*Id.* at 10). Constellation, IGS, and RESA stress that these provisions would mitigate risk and reduce costs for current SSO customers by removing the costs associated with large loads potentially migrating on to and away from the SSO (*Id.* at 11, 13). Moreover, Constellation indicates that not all details need to be resolved in this proceeding, but the alternative is leaving increasing risk premiums imbedded in current SSO pricing with a significant risk of massive migration of load to and from the SSO. IGS further explains that under the 10/10 Stipulation, if a Schedule EIC customer did not choose a supplier, it would be assigned to a supplier's standard monthly rate product called a Supplier of Last Resort (SOLR). IGS attests that as both a retail market supplier and an SSO supplier, establishing the default service for Schedule EIC customers and existing customers with ESAs through the SOLR program's selection process appropriately balances the interest of protecting the SSO while providing these customers a competitive default service rate. (IGS Ex. 1 at 6-7.) Additionally, RESA asserts that while AEP Ohio withdrew their SSO provisions in the 10/23 Stipulation, this is the proper proceeding to discuss such solutions. RESA points out that hyperscale data centers and other very large nonresidential customers on Schedule EIC in the future are very sophisticated customers that can appropriately select the type of retail electric generation supply option that fits their business needs. (Constellation at 21-22, 25-26; RESA Br. at 15; IGS Br. at 8-9.)

{¶ 87} Regarding the SSO provisions, AEP Ohio insists that the Commission should reject the SSO alternative proposal under the 10/10 Stipulation in this case and take the issues up on a prospective basis in a separate docket, consistent with the settlement adopted by the Commission in *In re Ohio Power Co.*, Case No. 23-23-EL-SSO (*AEP Ohio ESP V*), Joint Stipulation and Recommendation (Sept. 6, 2023) (case providing for continuing jurisdiction over SSO issues during the ESP term). Jointly, OCC and OPAE also assert that the SSO proposal is inconsistent with prior Commission guidance, as it has previously declined proposals to significantly change the SSO process outside of a single proceeding applicable to all electric distribution utilities (EDUs), citing to *In re Ohio Edison Co., The Cleveland Elec. Illum. Co. and The Toledo Edison Co.*, Case No. 23-301-EL-SSO (*FirstEnergy SSO Case*), Opinion and Order (May 15, 2024) at ¶ 77; *In re Ohio Power Co.*, Case No. 23-23-EL-SSO, et al., Opinion and Order (Apr. 3, 2024) at ¶ 82; *In re Application cf the Dayton Power & Light Co. d/b/a AES Ohio*, Case No. 22-900-EL-SSO, et al., Opinion and Order (Aug. 9, 2023) at ¶ 247. Moreover, AEP Ohio opines that the 10/10 Stipulation incorporates a proposed SSO alternative that is against the public interest, unreasonable on its face, and patently inferior to the existing SSO. The Company believes that the hard-wired requirements only serve to ensure higher prices and CRES profits, unlike the existing SSO. In support, the Company cites to Mr. Indukuri's testimony that the "underlying motivation behind proposing the product structure" of the 10/10 Stipulation's SSO provision was to "attract suppliers who would come in and serve this load for the data center customers" (Tr. Vol. III at 641). On this point, AEP Ohio contends that Mr. Indukuri openly admitted that the mechanism eliminates risk as compared to the current SSO and requires the passthrough of costs – even though it purports to be a competitive SSO alternative. AEP Ohio also notes that witness Indukuri stated the "the details of the process" needed to be shored up by the Commission, which includes the auction rules and the boilerplate contract provisions (*Id.* at 647). AEP Ohio, thus, concludes that the to-be-determined portions of the proposal means that the 10/10 Stipulation signatories do not truly present a real solution that can be implemented and that the Commission would need to implement it in another docket. (AEP Ohio Br. at 73-76; AEP Ohio Reply Br. at 40; OCC/OPAE Reply Br. at 12.)

{¶ 88} In response, Constellation insists that the establishment of a separate procurement for large load customers is necessary to address what AEP Ohio characterized as an unacceptable risk and reduce premiums. Constellation believes this risk is paid for by all of AEP Ohio's customers in the form of higher than necessary risk premiums that directly impact SSO prices (Constellation Ex. 4 at 12). Moreover, Constellation insists that the 10/10 Stipulation's provisions do not contradict Commission precedent, as it has not expressed any blanket prohibition on making SSO changes in a utility-specific proceeding. Furthermore, RESA insists that the need for consistency (amongst all the EDUs) is outweighed by the need to take action to address the issue now. (Constellation Reply Br. at 7-8; RESA Reply at 10.)

vi. Regulatory Flexibility

{¶ 89} Some 10/10 Stipulation signatories assert that this stipulation aligns with AEP Ohio's stated goal of accurate forecasting, while remaining flexible enough to avoid subjecting large energy customers to unnecessarily stringent requirements. OMAEG believes that the 10/10 Stipulation incentivizes large energy users to be more accurate with their load forecasts and, as a result, have more "skin in the game" regarding potential transmission expansion. DCC specifically highlights that the minimum demand charges and the four-year load ramp schedule provisions would incentivize the large energy users to be more accurate with their capacity estimates. For example, any overestimate would result in the customer paying higher minimum demand charges than necessary during the load ramp period. Relatedly, Google indicates that the 10/10 Stipulation's ramp period structure offers a reasonable degree of flexibility to new large customers (including data centers) while assuring AEP Ohio that the load ramp will remain within manageable parameters (Google Ex. 1 at 21). DCC also stresses that the collateral provision in the 10/10 Stipulation is a mechanism that encourages Schedule EIC customers to accurately estimate their capacity needs since overestimates would lead to the customer paying more collateral than necessary. (OMAEG Initial Br. at 41; DCC Initial Br. at 34; Google Initial Br. at 22.)

{¶ 90} ADS and DCC further underscore that the 10/10 Stipulation, as a package, strikes a balance for large energy customers while aligning with AEP Ohio's goals of establishing a regulatory framework of realistic load estimates, appropriate recovery of transmission costs for the Company, and the avoidance of stifling continued data center development in Ohio. Google witness Baatz indicated that the 10/10 Stipulation properly gives customers the flexibility to select terms that best fit with their individual business needs, while mitigating AEP Ohio's risk of under-recovery for additional transmission buildout (Google Ex. 1 at 21). OMAEG also emphasizes that the 10/10 Stipulation provides Schedule EIC customers the requisite flexibility to construct and operate their facilities per their business models, as well as the option to exit after a certain period after paying a fee if infrastructure is not constructed or other market constraints exist. Further, ADS witness Fradette insists that a measure of flexibility for large load customers is required in setting minimum billing demand charges for multiple reasons. First, the flexibility required in data center planning, development, and operation ensures efficient utilization of capacity for the benefit of all ratepayers. Another reason for flexibility are data centers' cooling needs, which is weather and seasonal dependent. Also, data centers plan for worst case design loading events to ensure reliability, which recognizes that actual peak loads will generally operate below such a level. Lastly, Mr. Fradette explained that data centers will continue to innovate throughout the ten years and longer duration, which could result in design modifications to both planned and existing data centers that could change estimated peak loading requirements. (ADS Ex. 8 at 12.) ADS also urges the Commission to find that the 10/10 Stipulation meets the second prong based on the matter of fairness, stating that this stipulation prevents data centers from being obligated to unfairly pay the bill when other large load customers in AEP Ohio's territory fail to materialize. (DCC Initial Br. at 35-36; ADS Initial Br. at 11-14; OMAEG Initial Br. at 39.)

{¶ 91} In response, AEP Ohio emphasizes that the 10/10 Stipulation fails to protect current and prospective customers in all customer classes. The Company reiterates its position that the 10/10 Stipulation solely promotes the development of the data center business sector at the expense of other important industries seeking to locate in Ohio, particularly where those other industries are the impetus for this proceeding. Moreover, AEP Ohio insists that the 10/10 Stipulation, as a package, could threaten grid reliability. Specifically, the Company argues that the 10/10 Stipulation's provisions regarding resizing of contract capacity lacks certain material safeguards necessary to protect the utility, grid, and customers (AEP Ex. 3 at 37-38). OCC and OPAE add that the 10/10 Stipulation creates minimum demand levels that are too low and do not address concerns of speculative forecasting. And as a result, the less accurate forecast load would benefit data centers, but unreasonably shift risk and costs to all other consumers (OCC Ex. 2 at 5, Staff Ex. 1 at 50). Staff also clarifies that data centers could be more incentivized to overestimate their loads because of the lower minimum demand charges. Furthermore, AEP Ohio and OEG contend that the 10/10 Stipulation's provisions would create an unlawful secondary market for capacity by allowing customers to assign up to 50 percent of their contract capacity to another Schedule EIC member (AEP Ex. 3 at 40-41). (AEP Ohio Br. at 63; AEP Ohio Reply Br. at 34-35; OEG Initial Br. at 15-16 OCC/OPAE Initial Br. at 27; Joint Reply Br. at 10; Staff Initial Br. at 34.)

{¶ 92} To the contrary, ADS underscores that the majority of parties to this proceeding support the 10/10 Stipulation. According to ADS, this stipulation offers flexibility to large energy users, remains industry neutral, requires transmission constraint proof from the utility before transmission investments are made, and recommends a COI to review solutions to AEP Ohio's identified problem. ADS thus proclaims that the critical merit to the 10/10 Stipulation is that it does not impose a regulatory straitjacket. (ADS Reply Br. at 10-11.)

{¶ 93} For the abovementioned reasons and more, the 10/10 Stipulation signatories urge the Commission to find that the 10/10 Stipulation as a package, benefits customers and the public interest, and satisfies the second prong of the Commission's three-part test.

b. The 10/23 Stipulation

{¶ 94} AEP Ohio believes that the 10/23 Stipulation reconciles a number of competing interests and maintains an appropriate balance that furthers the interests of data centers while also safeguarding the interests of AEP Ohio's other customers and the public. AEP Ohio states that it is essential for it to accurately forecast load to ensure that the appropriate level of transmission structure is built. AEP Ohio highlights the unprecedented growth in data center demand in recent years and the anticipated surge in total demand in the central Ohio region. Based on this data center growth, AEP Ohio states that the 10/23 Stipulation proposes to limit the applicability of Schedule DCT only to new data centers exceeding 25 MW. AEP Ohio maintains that the record overwhelmingly shows that new and expanding data center customers are driving the need for substantial EHV transmission investments. In support of this, AEP Ohio points to the testimony and cross-examination of witness Ali. Mr. Ali explained that the substantial load growth in the central Ohio region is driving significant transmission constraints that must be addressed before they impact the stability and reliability of the entire grid (Tr. Vol. I at 66). AEP Ohio stresses that new and expanding data center customers – *not* traditional manufacturing or other large load customers – are driving the exponential load growth and the associated need for transmission investments. Mr. Ali testified that, currently, only 600 MW of the existing peak demand of 4,000 MW in central Ohio is attributable to data center customers. However, in recent years, AEP Ohio has signed ESAs and/or LOAs for new load to add 4,400 MW of load to central Ohio by 2030 and only 400 MW, or eight percent, of that anticipated load growth is from non-data center customers. Further, Mr. Ali testified that the Company has also received load requests of 30,000 MW from data center customers that have not yet signed an agreement. Based on a series of studies run by the AEP Ohio Transmission Planning organization, even a fraction of the anticipated 30,000 MW load would result in numerous overload and voltage violations throughout central Ohio. (Sidecat Ex. 10 Tr. Vol I at 115, 119, 123, 187, 226-235; AEP Ex. 2 at 3-5.) According to AEP Ohio, this unparalleled load growth will require significant EHV transmission investment. (AEP Ohio Br. at 38, 41-42.)

{¶ 95} AEP Ohio submits that the 10/23 Stipulation proposes a data center-specific solution for a data center-specific problem. Rather than subject *all* customers with loads exceeding 50 MW to the new tariff, AEP Ohio represents that Schedule DCT will maintain the status quo for traditional manufacturing and other large customers, while requiring additional commitments from data center customers for the issues that only data centers are causing. AEP Ohio insists that this structure will maintain Ohio's competitiveness in attracting large-scale manufacturing customers and other large job creating entities. (AEP Ohio Br. at 44-45.)

{¶ 96} AEP Ohio also avers that the 10/23 Stipulation is in the public interest because it will facilitate AEP Ohio providing accurate estimates of forecasted load to PJM, which in turn will allow the "right-sizing" of the transmission system and any necessary improvements. The Company notes that, as a regulated utility, it is obligated to make the full amount of a customer's contracted load available; under current Schedule GS; however, AEP Ohio believes data customers are encouraged to overestimate their load needs by signing up for more power than they need. AEP Ohio argues that the 10/23 Stipulation provides reasonable incentives for data centers to accurately estimate their load needs, while also apportioning the risk of underutilized investments in a reasonable fashion. AEP Ohio asserts that the minimum demand provisions in the 10/23 Stipulation – with a sliding scale capped at 85 percent of contract capacity – ensure that data centers offset the costs of infrastructure built to serve them, lessening the likelihood of such costs being shifted to other customers. (AEP Ohio Br. at 48-51.)

{¶ 97} AEP Ohio believes that the contract term and exit fee provisions in the 10/23 Stipulation are in the public interest, as they will provide tangible benefits to ratepayers. This is accomplished by giving data centers "more skin in the game" than they currently have under Schedule GS or would have under the 10/10 Stipulation. AEP Ohio avers that the initial contract term (up to four years of load ramp period, plus eight years) and the exit fee provisions (equal to three years of minimum charges; available following the fifth year after the load ramp period) work together to protect the Company's customers, while still allowing sufficient flexibility to data center customers whose plans could change over time. The 10/23 Stipulation ensures that data center customers will make significant revenue contributions throughout the life of their contracts, including during the load ramp period, but AEP Ohio believes it does so in a balanced manner – the minimum billing starting at 50 percent of contract capacity during the first year of the load ramp, then tapering up slightly each year, allowing a data center customer to grow into its operations. Similarly, AEP Ohio argues that the collateral provisions in the 10/23 Stipulation are essential to safeguard the public. By maintaining the collateral and credit requirements proposed in the initial application, AEP Ohio believes it will ensure that data center customers are financially sound and further reduce the risk of cost-shifting. AEP Ohio also lists customer protections it deems critical, which it says are included in the 10/23 Stipulation but omitted from the 10/10 Stipulation. (AEP Ohio Br. at 51-55.)

{¶ 98} AEP Ohio highlights the multiple refinements to the Company's application that are included in the 10/23 Stipulation. The Company notes numerous modifications it made to what was proposed in the application: eliminating the Mobile Data Center Tariff; lowering minimum demand charges; extending the load ramp period; establishing a clear and customer-friendly process for enrolling new data center customers; creating a regulatory liability for exits; withdrawal of the SSO proposal; and flexibility for contract adjustments. The Company states that each of these compromises were made in response to comments and input received from data center customers and other constituents. (AEP Ohio Br. at 55-57.)

{¶ 99} Finally, AEP Ohio stresses that as a regulated EDU, the Company has the obligation to operate the electric grid for the benefit of all of its customers. While AEP Ohio is required to provide service to all customers within its service territory, it must do so in a manner that does not threaten the availability of safe, reliable, and adequate service throughout the entire system. Thus, AEP Ohio lists seven key provisions of the 10/23 Stipulation that it feels are essential, such as requiring load from affiliated companies to be aggregated for minimum demand purposes, foreign adversary provisions, and netting of BTM generation, among others. Each of these provisions, AEP Ohio asserts, will protect other customer classes from potential interruptions caused by the significant increase of data center demand. Further, AEP Ohio states that it has a right to run its business as it deems appropriate in order to meet its obligations to continue providing safe and reliable service. The Company believes that the extra requirements found in the 10/10 Stipulation would negatively impact its business and the efficient operation of the grid. In contrast, AEP Ohio believes that the protective terms of the 10/23 Stipulation effectively protect all customer classes while still allowing the Company to continue operating in a manner consistent with Commission regulations and statutes. Accordingly, the Company insists that as a package, this stipulation furthers state policy to ensure that customers have access to "adequate, reliable, safe, efficient, nondiscriminatory, and reasonably priced retail electric service," as stated in R.C. 4928.02(A) (AEP Ex. 4 at 34-35). As a result, AEP Ohio believes that the 10/23 Stipulation appropriately addresses the Company's challenges regarding the rapid growth of data center load within central Ohio without needlessly discouraging Ohio's competitiveness with other states and nations to attract new manufacturers and other large job creators (AEP Ex. 4 at 39-40). (AEP Ohio Br. at 11, 57-60, 66-68, 79.)

{¶ 100} In summary, AEP Ohio submits that the 10/23 Stipulation, as a package, benefits ratepayers and is in the public interest. Other 10/23 Stipulation parties agree with this assessment, for largely the same reasons outlined above by AEP Ohio. Staff underscores the key provisions that maintain the status quo for non-data center customers while increasing commitments from prospective data center customers (Staff Initial Br. 11-25). OEG and OCC and OPAE, jointly, highlight similar provisions, believing that the 10/23 Stipulation strikes a balance that is in the public interest (OEG Initial Br. at 6-18; OCC/OPAE Initial Br. at 19-24). Walmart agrees that requiring stronger commitments from data center customers, as opposed to current Schedule GS or what is proposed in the 10/10 Stipulation, benefits ratepayers and the public interest (Walmart Br. at 6-9.)

{¶ 101} Multiple 10/10 Stipulation signatories find the terms of the 10/23 Stipulation to be unreasonable and against the public interest. ADS points to the 10/23 Stipulation's contract length and load ramp provisions as being inflexible and too restrictive. Additionally, ADS argues that the collateral and exit fee provisions impose substantial requirements only on data center customers, which again indicates that the stipulation, as a package, is not in the public interest. OBC, likewise, argues that the discriminatory terms of the 10/23 Stipulation harm the public by discouraging economic development in Ohio. OBC states that the 10/23 Stipulation imposes unnecessary financial burdens and other commitments on data centers, thus increasing their costs to do business in the state. OBC further argues that the discrimination of certain industries would also create an unstable regulatory environment that may deter data center customers from coming to Ohio. Google echoes the sentiments of OBC, stating that an unstable regulatory environment will make it difficult to attract new economic development opportunities. (ADS Initial Br. at 25-28; OBC Initial Br. at 33-35; Google Initial Br. at 27-28.)

{¶ 102} In addition to the 10/23 Stipulation signatories' multiple abovementioned arguments, Buckeye and AMP are non-signatories to either of the stipulations, but believe that, as between the two proposals, the 10/23 Stipulation is reasonable and provides necessary protections to other customers. In its briefed arguments, Buckeye and AMP jointly indicate that the 10/23 Stipulation provisions, including minimum demand charge, minimum contract terms, exit fees, and load ramp provisions, are reasonable. Furthermore, Buckeye and AMP believe that preventing BTCR pilot participation is beneficial, because allowing data center participation in that pilot would shift recovery of the data centers' sunken costs and its load serving entity to other customers. Buckeye and AMP also characterize the 10/23 Stipulation's proposed BTM provisions as reasonable and necessary. Generally, Buckeye and AMP confirm that using BTM generation to reduce electric demand of high load factor customers does nothing to reduce transmission costs. Lastly, Buckeye and AMP assert that the 10/23 Stipulation's terms allowing retail capacity reassignment are reasonable compared to the 10/10 Stipulation's similar provisions. As such, the 10/23 Stipulation recognizes that retail capacity has been made available for an existing data center customer under its ESA, which is often dependent on transmission and distribution upgrades that are tailored to a specific location. In comparison, Buckeye and AMP insist that the 10/10 Stipulation fails to include those protections and allows up to 50 percent transfer with no qualifications relating to cost responsibility, avoiding stranded costs, or technical feasibility. (Buckeye and AMP Br. at 12-13, 18, 21-22.)

{¶ 103} For the reasons espoused above and presented in briefed arguments and record evidence, the 10/23 Stipulation signatories request the Commission to find that the 10/23 Stipulation, as a package, is superior to the 10/10 Stipulation and thus benefits customers and the public interest and satisfies the second prong of the Commission's three-part test.

c. Consideration of Other Issues

i. Speculative Load Concerns

{¶ 104} Some parties even question the need for a new tariff, or the extent of the future load requests alleged by AEP Ohio. Sidecat asserts that, except for vague statements that many companies expressed "interest" in future projects, AEP Ohio provided no evidence to support its claim that 30,000 MW of new load will soon come onboard in central Ohio. ADS also argues that AEP Ohio has provided little concrete evidence for the alleged "transmission constraints" that prompted the filing of the application in this case. Even if the AEP Ohio assertions as to incoming demand in central Ohio are accepted, parties like OBC believe that the lack of a requirement to prove a "transmission capacity constraint" before subjecting a customer to Schedule DCT is unwarranted. OBC states that not requiring proof of a constraint will subject customers to Schedule DCT even in areas where there may be readily available transmission capacity and thus no need for significant transmission investments. One Power expresses similar sentiments, arguing that if an area has sufficient capacity available, the more "onerous" terms of Schedule DCT would be unnecessarily applied to certain customers. (Sidecat Br. at 9-10; ADS Reply Br. at 2-3; OBC Initial Br. at 35-36) Br.

{¶ 105} Contrarily, AEP Ohio points to what it believes to be "overwhelming" record evidence that demonstrates the emergence of transmission capacity constraints throughout the AEP Ohio service territory. AEP Ohio insists that the identified transmission constraint is not mere speculation by the Company, but it is supported by ample evidence in pre-filed testimony and in evidentiary hearing record evidence. The Company asserts that opponents of the 10/23 Stipulation ignore testimony such as that of witness McKenzie, who provided illustrations of AEP Ohio historical peak demand and the projected exponential growth of demand from incoming data center loads based on signed ESAs. (AEP Ex. 3 at 3-4.) AEP Ohio stresses that the testimony of witness Ali is beyond mere speculation, as it relates to the 4,400 MW to be added by 2030, based on executed ESAs, and the over 30,000 MW requests from data centers (AEP Ex. 2 at 3-5). The Company further notes that while parties may oppose specific provisions of the 10/23 Stipulation, no party has introduced any evidence that contradicts or even casts doubt on the Company's findings of the risk of transmission constraints emerging within its service territory. Furthermore, AEP Ohio fully concedes that the 30,000 MW of unsigned data center load is not certain to ultimately appear. Rather, the entire purpose of this proceeding is to verify how much of that anticipated load will appear to avoid overbuilding transmission infrastructure. (AEP Ohio Reply Br. at 24-25, 27.)

ii. Discrimination Concerns

{¶ 106} While the 10/10 Stipulation signatories dispute that the 10/23 Stipulation is the correct solution to the issues presented by AEP Ohio, the critical difference between the two stipulations is that one applies to all large energy-intensive customers, while the 10/23 Stipulation is tailored to address data center customers. Those opposing the 10/23 Stipulation acknowledge that it does take steps to mitigate stranded investment risk and to encourage accurate capacity estimates, but these parties contend that it does so in a discriminatory and unnecessarily onerous manner. The overriding objection by the 10/10 Stipulation parties is that the 10/23 Stipulation and its associated Schedule DCT violate Ohio law by making it applicable *only* to data center customers. While the parties acknowledge that complete uniformity in rates or prices is not required, they note that utilities are permitted to distinguish between customers only under certain conditions. The 10/10 Stipulation parties argue that Schedule DCT is unjustly discriminatory and in violation of Ohio law. They point to R.C. 4905.35 and 4905.33, which prohibit a public utility from charging two customers differently where the service provided to those customers is "a like and contemporaneous service under substantially the same circumstances and conditions" (R.C. 4905.33(A)). DCC notes the Ohio Supreme Court's decision in *Mahoning County v. Public Utilities Com.*, 58 Ohio St. 2d 40 (1979), where the Court held that distinguishing between two customers receiving a like and contemporaneous service under substantially the same circumstances and conditions requires a utility to show some "actual and measurable differences" in the furnishing of services to a customer.[6] DCC further notes the Court's decisions in *Buckeye Lake Chamber cf Commerce v. Public Utilities Com.*, 161 Ohio St. 306 (1954) and a FERC decision[7] in which FERC applied a similar standard. In this case, numerous parties argue that AEP Ohio failed to provide any actual and measurable difference between the service, or the circumstances and conditions of that service, that AEP Ohio provides data center customers and other large load customers. With respect to the service provided, DCC maintains that there is no dispute that the Company renders the same service to data centers and other similarly sized large load customers. Regarding the circumstances and conditions, multiple parties argue that AEP Ohio provided no quantitative analysis to demonstrate that there is (1) a difference in the cost of serving data

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6 *Mahoning Cty. Twps. v. Pub. Util. Comm.*, 58 Ohio St. 2d 40 (1979) at 43-44.

7 7 *In re Basin Elect. Power Cooperative, Fed. Energy Reg.* Comm., Docket Nos. ER24-1610-000, ER 24-1610-001, Order Rejecting Proposed Rate Schedules (Aug. 20, 2024).

centers and other large load customers and (2) a difference between the risk associated with servicing data center customers and other large load customers. Sidecat states that the only study results produced by AEP Ohio was a one-page summary of three load scenarios studied by AEP's Transmission Planning group – a far cry from a credible, quantitative study, in Sidecat's estimation (Sidecat Ex. 10). And instead, according to Sidecat AEP Ohio relies on generalized claims from witnesses Ali and McKenzie as to the unique nature of the data center industry. In the estimation of the 10/10 Stipulation parties, these broad, unsubstantiated claims are not "actual and measurable differences" required to justify such discrimination. (DCC Initial Br. at 38-55; ADS Initial Br. at 20-24; Google Initial Br. at 9-10, 27-28; One Power Initial Br. at 21-22, 25-28; Sidecat Br. at 7-8; OBC Initial Br. at 30-32.)

{¶ 107} In response, AEP Ohio highlights that both the Commission and Ohio Supreme Court have consistently held that a utility's tariff is considered unduly discriminatory only if it treats similarly situated customers differently without justification, citing to *Allnet Communications Serv., Inc. v. Pub. Util. Comm.*, 70 Ohio St.3d 202, 207 (1994) (*Allnet Case*) (under R.C. 4905.35(A), "discrimination is not prohibited *per se* but is prohibited only if without a reasonable basis."); *see also Weiss v. Pub. Util. Comm.*, 90 Ohio St.3d 15, 16 (2000) (holding that R.C. 4905.33 prohibits discriminatory pricing for "like and contemporaneous service" rendered "under substantially the same circumstances and conditions," but does not prohibit differences in prices charged or collected where the utility services rendered are different or if they are rendered under different circumstances or conditions); *see also Meyers v. Pub. Util. Comm.*, 64 Ohio St.3d 299, 302 (1992) (emphasizing that a utility's residential and general service classifications and their corresponding rates are based upon actual and measurable differences in the furnishing of services to customers and, therefore, are not unduly discriminatory). The Company concludes therefore, that "[d]ifferences reasonably affecting the expense or difficulty of performing the same or similar service in different areas or circumstances may be reflected in differences in cost recovery rates, and ... such differences are neither unlawful nor discriminatory," citing to *Migden-Ostrander v. Pub. Util. Comm.*, 102 Ohio St.3d 451, 459 (2004) (*Migden-Ostrander Case*).

AEP Ohio believes consistent with this authority, it is appropriate and commonplace in utility regulation to recognize different classes of customers and subject them to different tariff schedules, when those classes of customers are based on tangible, reasonable, and justifiable distinctions (AEP Ex. 4 at 35- 36). (AEP Reply Br. at 46-49.)

{¶ 108} AEP Ohio asserts that every schedule in the Company's current tariff, except Schedule GS, makes reasonable distinctions between different classes of customers based on the customer's use of power and the level of power needed, in addition to the end use and customer identity. In support, the Company lists some example of distinct customer classes, including county and independent fairs, lighting customers, schools, churches, power plants, customers utilizing BTM generation, customers with electric vehicles, automakers, and electric heating customers. As such, AEP Ohio argues that Schedule DCT represents just one more rate schedule in a long list of comparable tariffs offered by the Company. AEP Ohio accordingly indicates that there are several distinctions that justify applying different tariff schedules to new and expanding data centers within AEP Ohio's service territory (AEP Ex. 4 at 37-39). First, the Company insists that the record has demonstrated that the data center load is the impetus of unique and unprecedented demand load growth unseen for other types of large loads (AEP Ex. 4 at 37). In order to serve such a unique, concentrated load, the Company represents that it must construct significant infrastructure, making data centers particularly risky customers (AEP Ex. 4 at 38). As a result, data centers bring with them systematic, industry-wide risks not present for other types of customers (AEP Ex. 4 at 38-39). AEP Ohio reiterates that these risks involve concerns over underutilization of the electric infrastructure built, should data centers experience an industrywide downturn or the demand does not materialize for these kinds of customers. Moreover, AEP Ohio believes that, unlike non-data center load — which comprises a diverse group of customer end uses — data center load cannot be mitigated by marginal ups and downs of other industries in AEP Ohio's service territory (AEP Ex. 4 at 38-39). The Company, thus, urges the Commission to agree that Schedule DCT offers reasonable conditions of service designed to address the Company's transmission constraint issues while providing a balanced solution that accounts for the unique circumstances and features of new and expanding data centers in central Ohio, such that its terms cannot be considered unduly discriminatory under either R.C. 4905.33 or R.C. 4905.35. (AEP Ohio Br. at 79-82.)

{¶ 109} In its briefed arguments, OEG insists that the 10/23 Stipulation is not unduly or unreasonably discriminatory. For one thing, OEG points out that under the 10/23 Stipulation, if data centers accurately forecast load and use what they need, they will pay exactly what they would pay under Schedule GS. OEG explains that the only differences between the two stipulations involve terms and conditions of service, not rates. The actual rates (demand charges, energy charges and riders) that data center/cryptominers would pay under either stipulation are exactly the same as those paid by all other comparable Schedule GS customers. Under both stipulations, data centers/cryptominers would pay the exact same BTCR energy and demand rates as comparable Schedule GS customers. As such, because both stipulations would charge exactly the same rates, OEG declares that the 10/23 Stipulation cannot be deemed as discriminatory against data centers/cryptominers with respect to rates. (OEG Initial Br. at 19-20.)

iii. AEP OHIO'S MORATORIUM

{¶ 110} Multiple 10/10 Stipulation signatories represent that AEP Ohio's moratorium of service to data centers was unlawful and discriminatory. Notably, Google insists that no matter what course the Commission takes regarding the proposed stipulations, the Commission must order the Company to lift its unlawful moratorium. Google is very concerned that AEP Ohio waited over a year after the moratorium was enacted before it notified the Commission via the public filing of its application in this proceeding. One Power, OMAEG, and Sidecat contend that the moratorium's implementation is an admission by the Company that it cannot fulfill its obligation to serve all customers within its service territory, in violation of RC 4905.22 (AEP Ex. 1 at 7). Google, One Power, and Sidecat also maintain that the moratorium runs counter to R.C. 4933.83(B), which obligates the Company to meet the reasonable needs of consumers and inhabitants within its certified territory and to render "physically" adequate service. Sidecat emphasizes that the Commission has already determined that "physically adequate service" under R.C. 4933.83(B) goes beyond just providing "reliable service." Rather, utilities are obligated to provide "physically adequate service," which entails providing a sufficient electricity supply to meet customers' loads, citing to *In re Ormet Primary Aluminum Corp. and Ormet Aluminum Mill Prods. Corp. v. South Central Power Co. and Ohio Power Co.*, Case No. 05-1057-EL-CSS (*Ormet Case*), Opinion and Order (June 14, 2006) at 11. OMAEG also alleges that the complete halting of service to data center customers violates the Certified Territory Act. One Power and OMAEG concur that AEP Ohio can continue to serve data center customers under its existing tariffs and existing generation and transmission planning process but chooses not to do so. Relatedly, Google emphasizes that at no point did the Company put non-data center customers on a moratorium. (Google Initial Br. at 8; Sidecat Br. at 6; One Power at 19-20; OMAEG Initial Br. at 43.)

{¶ 111} Sidecat also laments that the Company has not sufficiently justified its moratorium or its proposed data center-only tariff. Generally, Sidecat expresses frustration that the Company has failed to turn over the transmission studies that led to the implementation of its moratorium and inception of the proposed tariffs, or those studies that were conducted after the moratorium's outset. Sidecat acknowledges that Staff requested studies or the results of any studies related to AEP's Transmission Planning group's assessment of the additional data center load requests. However, Sidecat is dismayed that the Company only produced a one-page summary of three load scenarios that the Company completed before the moratorium was implemented in early 2023 (Sidecat Ex. 10). Sidecat emphasizes that the Company did not enter into the record anything that describes the additional analyses conducted by the Company's Transmission Planning group after the moratorium. Moreover, there is no evidence that indicates Staff received any subsequent studies or the like. Sidecat thus insists that the one-page summary, by itself, does not demonstrate the need for the Company's current moratorium and likewise, a need for any data center-specific tariff. As a result, Sidecat lists the following as details necessary to justify the additional and considerable costs the 10/23 Stipulation would impose on a specific segment of AEP Ohio's large volume customers: "(i) the potential solutions to AEP Ohio's reliability concerns; (ii) the specific types of transmission and distribution capital investments that could be constructed to alleviate these concerns; (iii) the estimated costs and timetables to implement these capital investments; or (iv) any alternative solutions to large transmission capital investments." Lastly, Sidecat does concede that these concerns should not be construed as a lack of concern for the potential reliability issues caused by adding more load to the central Ohio electrical grid. However, due to the extraordinary circumstances of implementing a moratorium of service and asking for a data center-only tariff, Sidecat believes that the Company needed to provide more than one summation of its studies to justify its concerns and measures proposed in the 10/23 Stipulation. (Sidecat Br. at 7-9.)

{¶ 112} Furthermore, DCC, OBC, and OMAEG take issue with the moratorium as it pertains more closely with the first prong of the Commission's test. Specifically, DCC expresses concern that AEP Ohio is prepared to keep up the moratorium and improperly withhold service from data centers should the Commission make a determination that the Company dislikes. OBC and OMAEG believe that the self-imposed and self-authorized moratorium improperly extracts unfair financial concessions from the data center customers, held captive by the moratorium queue and outcome in this proceeding. (DCC Initial Br. at 56; OBC Initial Br. at 29; OMAEG Initial Br. at 27-28.)

{¶ 113} Contrary to the positions presented by the 10/10 Stipulation signatories, AEP Ohio insists that the moratorium was a temporary, reasonable, and lawful solution to address the identified risk of significant capacity constraints within central Ohio. In direct response to OMAEG, OBC, One Power, Google, and Sidecat's allegations regarding violations of R.C. 4905.22 and 4933.83, the Company admits that it has a general obligation to serve customers. However, AEP Ohio declares that such an obligation is not without limits, and both statutes pose an obligation to service only within the bounds of reason. The Company explains that R.C. 4905.22 qualifies providing service "in all respects just and reasonable," while R.C. 4933.83 regards AEP Ohio deploying facilities to meet "the reasonable needs of the consumers and inhabitants in the certified territories." And AEP Ohio concedes that R.C. 4933.83 also requires AEP Ohio to provide "physically adequate service" which includes not only "reliable service" but also "supplying a sufficient quantity of electricity to meet the customers load," citing to *Ormet Case*, Opinion and Order (June 14, 2006) at 11. AEP Ohio, thus, reasons that Ohio law does not require the Company to extend service to customers in such a manner that would be unreasonable or impose unjust risks for the Company and its other customers. The Company notes that in the *Ormet Case*, the regulated utility could not take on the customer's load without risking the ability to provide reliable and sufficient service to the rest of its customers and, therefore, the Commission determined that the utility was not providing physically adequate service. As such, the Company believes this is comparable to the situation it faces today. AEP Ohio reiterates that an internal planning study performed during the summer of 2023 indicated that adding more load without significant reinforcement to the grid could cause a voltage collapse and, thus, brownouts and blackouts for its customers. Therefore, in 2023, had AEP Ohio committed to serving the full extent of additional data center load seeking to locate within its service territory, the Company believes it would have jeopardized its ability to provide reliable and sufficient service to the rest of its customers. Whereas, if AEP Ohio only committed to serving a portion of the requested data center load, it would not have been providing physically adequate service to those customers. Thus, the Company indicates that it proactively initiated this case before the Commission to seek a solution that would allow it to provide physically adequate service to new data center customers and the Company's other existing customers. Moreover, AEP Ohio states that it could have outright rejected the data centers' requests for service, and instead, the Company implemented the temporary moratorium, in which all affected customers were notified of this decision. (AEP Ohio Reply Br. at 43-45.)

{¶ 114} Further, AEP Ohio indicates that there is well-established case precedent that recognizes the Commission may not direct an extension of facilities, if the regulated utility is not receiving adequate compensation for the services it is already providing, citing to *People of State of New York ex rel. Woodhaven Gaslight Co. v. Pub. Serv. Comm'n of New York*, 269 U.S. 244 (1925); *Forest Hills Util. Co. v. Pub. Util. Com.*, 31 Ohio St.2d 46, 56-57 (1972). Thus, AEP Ohio believes that it would run counter to such foundation precedent if the Company is obligated to build out significant transmission infrastructure and to serve the new data center load without necessary safeguards to ensure that the load will actually materialize. (AEP Ohio Reply Br. at 45)

iv. OTHER JURISDICTIONS

{¶ 115} Those opposed to the 10/23 Stipulation also point to solutions implemented in other states by sister companies of AEP Ohio. For instance, in Indiana, Indiana Michigan Power Company (I&M) sought to revise its industrial tariff to address large load customers, similar to the circumstances of this case. Multiple 10/10 Stipulation signatories highlight that I&M ultimately entered into a unanimous stipulation in which the "large load terms" would apply to *all* customers taking service at certain contract capacities, not exclusively on data centers (DCC Ex. 11). According to DCC, the Indiana Utility Regulatory Commission approved that stipulation in February 2025. Similarly, a stipulation was entered into by Appalachian Power Company and Wheeling Power Company (APCo), pursuant to which APCo's proposed new large load terms would apply to any new load, or expansion of existing load, at specified contract capacities. DCC submits that the size of new load is the true issue, and it stands to reason, therefore, that any new tariff designed to mitigate the risks inherent in new large loads should be applied on a non-discriminatory basis. Since such a non-discriminatory tariff was possible for AEP Ohio affiliates, DCC, ADS, and One Power argue that AEP Ohio can adequately address its issues in central Ohio through a similar tariff that does not distinguish between data centers and other large load customers. To do otherwise, they contend, goes against the public interest. (DCC Initial Br. at 58-59; ADS Initial Br. at 16-17; One Power Reply Br. at 15.)

{¶ 116} AEP Ohio responds by pointing out that there are significant differences between jurisdictions that could justify a varied approach to issues that, at first glance, may appear similar in nature. Unlike in Ohio, Indiana's electric service is fully regulated and bundled, which means that the utilities provide generation, transmission, and distribution service. Within this regulatory framework, the Company explains that if a utility overbuilds its system, it can mitigate or resell generation into the market to offset stranded costs associated with those unnecessary investments. However, AEP Ohio notes that this is not the case in Ohio. If the utility overbuilds transmission, it has no ability to offset stranded investments unlike its Indiana counterparts. Moreover, the Company indicates that the 10/10 Stipulation signatories fail to discuss all the elements of the stipulations in those states, including provisions that increase costs for data centers for the benefit of all other customers. Furthermore, as AEP Ohio witness Ali explained during hearing, Ohio is the only AEP region that is currently experiencing constraints which go beyond local upgrades or incremental facilities (Tr. Vol. II at 443). Simply put, AEP Ohio underscores that the transmission infrastructure upgrades outside of Ohio are driven by data center load but are not necessarily causing the type of systematic transmission constraints currently facing the central Ohio region. (AEP Ohio Reply Br. at 55-56.)

{¶ 117} Relatedly, Staff insists that the Commission should not give any weight to the authority cited by the 10/10 Stipulation signatories. Notably, Staff believes that the stipulations in Indiana and West Virginia should not be given precedential value. Moreover, there are examples of other states, Idaho, Arkansas, and Wyoming, that have approved separate end use tariffs (or riders) similar to what the 10/23 Stipulation signatories propose and, as such, the Commission should find that the 10/23 Stipulation is reasonable and protects Ohio ratepayers. (Staff Reply Br. at 16-17.)

{¶ 118} Staff reiterates that the 10/23 Stipulation's provisions do not expressly discriminate against data centers and does not target such customers. Rather, the proposed tariff reasonably distinguishes data centers from other customer types based on demonstratable and material differences between data centers and non-data centers. In support, Staff notes that other jurisdictions have approved tariffs that apply to one type of end-use customer, including data centers. For instance, the Idaho Power Company (IPC) applied to the Idaho Commission for authority to establish a new schedule to service "speculative high-density customers," namely, large scale-cryptocurrency mining operations. In the proceeding, IPC received an increased cryptocurrency interest in load capacity and, if interconnected with the IPC system, it would have exceeded its ability to serve the total system load during that time period. Similar to AEP Ohio, IPC was concerned that the increased demand from the cryptocurrency operations coupled with limited capacity would probably constrain its ability to meet peak demand until at least 2026, citing to *In re Idaho Power Company's App. to Establish a New Schedule to Serve Speculative High-density Load Customers*, Case No.: IPC-E-21-37 (*Idaho Power Co. Case*), Order No. 35428 (June 15, 2022). The Idaho Commission approved IPC's application, authorizing it to establish a new customer classification applicable to high-density load customers. In this proceeding, the Idaho Commission praised IPC's approach for being proactive in mitigating potential stranded asset costs to its core customers, similar to AEP Ohio's concerns if data center load does not show up, citing to *Idaho Power Co. Case*, Order No. 35428. Also, a cryptocurrency-specific tariff was approved in Arkansas, where the Public Service Commission recognized that a proposed crypto-tariff was sensitive to the "flexible nature of cryptocurrency mining installation and the inherent unpredictability of crypto mining operations," citing to *In re Entergy Arkansas for a Proposed Tariff Regarding Large Power Highload Density*, Arkansas Case No. 22-032-TF (*Entergy Case*), Opinion and Order (Nov. 4, 2022) at *8. Furthermore, in Wyoming and similar to Staff's position, Cheyenne Light Fuel and Power d/b/a Black Hills Energy (Black Hills Energy) argued that blockchain customers are unique customers as large users of electricity and may represent loads of a limited duration. Thus, Black Hills Energy applied for a blockchain interruptible service tariff. The Wyoming Commission determined that there were legitimate concerns related to the permanence of blockchain customers and their intense electrical demand, and how to protect existing customers from the strain that these potential customers may bring. Notably, the Wyoming Commission also recognized Black Hills Energy's tariff as a proactive approach to balance the economic opportunity for the State of Wyoming by attracting these new industries with the risk posed to existing customers. Staff points to the Wyoming Commission's finding that Black Hills Energy's proposal, as modified by the stipulation, presented a tariff "that isolates existing customers from any increased capital costs or operating expenses, and the inherent business risks associated with blockchain customers," citing *to In re Cheyenne Light, Fuel, and Power d/b/a Black Hills Energy to Implement a Blockchain Interruptible Service Tariff*, Docket No.: 20003-173-ET-18, record No.: 15104 (*Black Hills Energy Case*), Memorandum Opinion, Findings, and Order Approving Stipulation (July 22, 2019) at 2.) (Staff Reply Br. at 14-16.)

v. WHOLESALE CONCERNS

{¶ 119} While in general favor of the 10/23 Stipulation, Buckeye and AMP insist that neither of the stipulations sufficiently addresses transmission cost-shifting concerns. Generally, Buckeye and AMP lament that the 10/23 Stipulation fails to ensure that retail customers of wholesale energy suppliers will be held harmless from transmission cost-shifting if a data center does not show up or stay. Buckeye and AMP note that there is no provision in either stipulation or in AEP Transmission Company, LLC's (AEP Transco) wholesale transmission tariff to ensure that the minimum demand charges and exit fees go directly to offsetting the stranded transmission costs caused by data centers and collected through AEP Transco's revenue requirement. Thus, Buckeye and AMP, jointly support a resolution in which any revenues collected under either proposed tariff will apply to AEP Transco's wholesale transmission revenue requirement. However, Buckeye and AMP recognize that the Commission may lack jurisdiction or legal authority to address these concerns and may be better addressed at FERC or in court. (Buckeye and AMP Br. at 24-26.)

{¶ 120} Briefly, in response, AEP Ohio notes that Buckeye and AMP concede that they may need to raise their wholesale concerns to the FERC level. AEP Ohio adds that Buckeye and AMP's concerns regard future wholesale impacts and issues, and are thus beyond the scope of this proceeding, as well as the Commission's jurisdiction. As a result, the Company asks the Commission to reject Buckeye and AMP's proposal. (AEP Ohio Reply Br. at 56-57.)

d. Conclusion

{¶ 121} The Commission finds that the 10/23 Stipulation benefits ratepayers and the public interest, striking the better balance of various interests between the two stipulations presented in this proceeding. Though the 10/10 Stipulation presents comparable provisions, it does not benefit all ratepayers and nor would it be in the public's interest to adopt such terms. In this Order, we deem that the Company has proven that there is a real, pending transmission constraint concern that stems from data centers' significant load growth, and that the 10/23 Stipulation is a proactive solution to address these challenges. Moreover, the 10/23 Stipulation aligns with important state policies in R.C. 4928.02, while protecting the interests of non-data center customers. Furthermore, we shall discuss why the 10/23 Stipulation does not unduly nor unlawfully discriminate against data center customers. And lastly, while not binding on this Commission, we find the actions of our public utility commission counterparts in other states to be helpful and informative in determining that implementing a specially tailored customer class to address the Company's transmission constraint concerns has merit and is a viable solution for the state of Ohio.

{¶ 122} Contrary to 10/10 Stipulation signatories' claims, the Commission determines that the Company has demonstrated a real transmission constraint concern that requires a solution. We recognize that AEP Ohio witness Ali testified that the existing peak demand in the central Ohio area makes up approximately 4,000 MW (600 MW being data center use) of the Company's 9,388 MW of peak load in 2023 (including wholesale interconnections). However, according to the Company, there is a contracted new load of existing and additional customers totaling 4,400 MW in the central Ohio areas by 2030, of which only 400 MW of that load growth is from non-data center customers. The Commission also recognizes Mr. Ali indicated that there are over 30,000 MW of unsigned data center load requests looking to connect to the transmission system in the greater Columbus area. (Tr. Vol. IX at 2039; AEP Ex. 2 at 3-5.) Based on a series of studies run by the AEP Transmission Planning organization, even a fraction of the anticipated 30,000 MW load would result in numerous overload and voltage violations throughout central Ohio. (Sidecat Ex. 10; Tr. Vol. I at 227-228). Regarding AEP Ohio's representation that there is unprecedented load growth solely originating from data centers, the Commission recognizes that the Company has initiated this proceeding as a proactive measure to address the concern that this unparalleled load growth will require significant transmission investments. On this point, we are not persuaded by 10/10 Stipulation signatories that claim the Company has not provided sufficient record evidence to demonstrate the transmission constraints AEP Ohio faces. As such, we find that the 10/23 Stipulation is the only proposed agreement that, as a package, presents a proactive solution that will protect other non-data center customers while remaining aligned with the state policies set forth in R.C. 4928.02.

{¶ 123} R.C. 4928.02(E) and (N) outline several policies critical to the state of Ohio, encouraging efficient access to information regarding the operation of the transmission and distribution systems of electric utilities and facilitating the state's effectiveness in the global economy, respectively. As AEP Ohio has made the Commission aware with the filing of its application, rapidly increasing data center load poses challenges for the state's grid reliability for all customers. The 10/23 Stipulation will incentivize more accurate estimates of forecasted load to PJM, which will result in efficient, right-sizing of the transmission system and any upgrades that must be made. Moreover, this stipulation safeguards other non-data center customers and appropriately apportions the risk of underused investments by requiring the cost-causers to bear an appropriate share of investment costs. Provided the significant transmission investments contemplated in this proceeding, the Commission agrees that right-sizing buildout and encouraging accurate forecasting are critical goals for preventing wastefulness and stranded investment costs, and thus unfairly imposing these costs onto non-data center customers. Here, the 10/23 Stipulation's terms as a package support these goals, including, but not limited to, the proposed minimum demand charge not to exceed 85 percent of total contract capacity, established term limits, exit fees that total a minimum of three years' minimum charges, gradual ramp-up period, and improved enrollment process. *See* 10/23 Stipulation Provisions B, D,E, F, J.

{¶ 124} Also, this stipulation ensures that incoming data center customers make a firm commitment to locating in the State of Ohio, while making reasonable concessions to encourage, rather than stifle, the data center industry in this state and thus maintain the state's role in the technology industry. For instance, the 10/23 Stipulation includes a grandfather clause, which carves out an exception for data center customers that are already established in the state and provides a buffer for such customers to expand up to 25 MW, before being converted to the new Schedule DCT. *See Id.* at Provision A. Incoming customers will also be given the opportunity to reassign contract capacity, so long as it does not result in stranded investments nor pose feasibility problems. *See Id.* at Provision G. Furthermore, the 10/23 Stipulation only ends AEP Ohio's enrollment and service moratorium for data centers when the Commission issues its decision in this matter. Overall, we find that the 10/23 Stipulation is a well-rounded package that will ensure that the critical information concerning transmission buildout and expansion is exchanged between AEP Ohio and its data center customers and that the amount of transmission buildout is proportional to the data center customers' needs, while not interfering with non-data center customers' service.

{¶ 125} The Commission also confirms that the 10/23 Stipulation provisions are not as onerous as the 10/10 Stipulation signatories represent. We agree with OEG's argument that if data centers accurately forecast their load and utilize their load as estimated, they should pay the same rates as they would under Schedule GS. The Commission also takes seriously OEG and AEP Ohio's concerns that should the 10/10 Stipulation be adopted, it runs the risk of creating an illegal secondary market for capacity by allowing customers to reassign 50 percent of their capacity. Therefore, it is in the ratepayers' and public's best interest to avoid such a risk, and it will promote administrative efficiency, if this

Commission does not have to regularly address customer capacity reassignment issues. Further, the stipulations contemplated in this case involve terms and conditions to interconnect and obtain AEP Ohio's service. Therefore, the actual rates that involve demand charges, energy charges, and current bill riders would have to be paid by data centers, regardless. Under both stipulations, data centers/cryptominers would pay the same BTCR energy and demand rates as Schedule GS customers (OEG Ex. 2 at 4). Moreover, DCC even admitted on brief that the 10/10 Stipulation and 10/23 Stipulation differed by a matter of degree and not categorical difference. Thus, it is in the ratepayers' and the public interest that the financial commitments required of data center customers under the 10/23 Stipulation would ensure that those customers bear a fair share of the relevant transmission build-out costs incurred to serve them. As such, we determine that the 10/23 Stipulation fully encapsulates a well-balanced package that accounts for non-data center customers on an industrial and residential level, while establishing a dependable, reasonable regulatory environment for data centers to continue to thrive within Ohio, pursuant to R.C. 4928.02's goal of facilitating the state's effectiveness in the global economy.

{¶ 126} Furthermore, in the interest of supporting the state's role in attracting a diverse industrial customer base that contributes to significant economic development on a state, national, and global level, the Commission modifies the 10/23 Stipulation's collateral provisions. We find that, the collateral requirements must either be met by the data center customer or the customer's financial sponsor, so long as the sponsor is a co-signer on the contract with AEP Ohio. In support of this modification, we first recognize that the majority of 10/10 Stipulation signatories are opposed to a collateral requirement, in general, arguing that collateral is not used for any other large energy-intensive users; that the Company admitted that it is unaware of any customer using 25 MW or more that declared bankruptcy in the last 10 years; and that excessive collateral requirements would stymie Ohio's attractiveness to businesses seeking to locate in the state. The Commission is mindful of all of these concerns, as this modification appropriately affords flexibility that accommodates the realities of corporate financing, while requiring the commitment level sought by the

10/23 Stipulation signatories (DCC Ex. 11 at 2; OMAEG Ex. 37 at 19-20; AEP Ex. 3 at 8-10, 19; OEG Ex. 1 at 5).

{¶ 127} The Commission also recognizes the SSO provisions' withdrawal from consideration and agrees that this proceeding is not appropriate to consider widespread changes to the SSO. The Commission recognizes the potential risk of large energy users, such as data centers, migrating to and from the SSO; and we find that whether necessary modification should be implemented is a decision best contemplated in a separate proceeding in the future.

{¶ 128} Next and importantly, the Commission affirms that the 10/23 Stipulation is not unduly discriminatory nor unlawful as alleged by the majority of 10/10 Stipulation signatories. The Commission acknowledges that the significant difference between the two proposed stipulations is the fact that the 10/23 Stipulation is specifically tailored to data center load, in excess of 25 MW, while the 10/10 Stipulation offers a new customer classification based on all large energy-intensive customers above a 50 MW threshold. The 10/10 Stipulation signatories claim that the 10/23 Stipulation unjustly discriminates against data centers and violates R.C. 4905.35 and R.C. 4905.33. Notably, the 10/10 Stipulation signatories assert that AEP Ohio has not sufficiently shown "actual and measurable differences" between the service, or circumstances and conditions of that service rendered to data centers and other large load customers. Here, opponents of the 10/23 Stipulation reiterate their dissatisfaction that AEP Ohio has not provided enough quantitative analysis to justify its proposal. Rather, we find the fundamental issue needed to be addressed is whether AEP Ohio has provided a reasonable basis for its tailored proposal. *See Allnet Case* (under R.C. 4905.35(A), "discrimination is not prohibited *per se* but is prohibited only if without a **reasonable basis**.") (emphasis added). And on this point, the Commission affirms that the Company has provided ample support that justifies the distinction amongst customers included in Schedule DCT.

{¶ 129} The Supreme Court of Ohio determined that differences reasonably impacting the "expense or difficulty of performing the same or similar service in different areas or circumstances" may be reflected in cost recovery variations/differences, which would not be deemed unlawful nor discriminatory. *Migden-Ostrander Case at ¶ 31*. The Commission is persuaded that the record evidence demonstrates that data center customers present differences that impact AEP Ohio's difficulty of delivering service to data center customers compared to other large energy-intensive customers. For one thing, the Company has proved that its transmission network will not be able to reliably serve any amount of load beyond the 4,400 MW load comprised of data center and non-data center customers that signed ESAs before the moratorium (Sidecat Ex. 10). The Commission is sensitive to AEP Ohio's representation that in order to serve such a unique, concentrated load, it must construct significant infrastructure, making data centers more risky customers. AEP Ohio's expert witnesses have testified that the Company has received service requests of 30,000 MW of data center loads, which justified the temporary pause in customer enrollment so that it could adequately plan for such a load growth (AEP Ex. 4 at 25). Based on the studies run by the AEP Transmission Planning organization, even a fraction of the anticipated 30,000 MW load would result in numerous overload and voltage violations throughout central Ohio (Sidecat Ex. 10). The Commission is sensitive to AEP Ohio's representation that in order to serve such a unique, concentrated load, it must construct significant infrastructure, making data centers more risky customers. Also, the Commission notes that it is not just the volume and highly intensive pattern of electric usage that distinguishes data center customers from other high intensive energy customers, like large manufacturers. The record clearly reflects that data centers can run at near capacity all day and every day and as such, they cannot shift their usage to off-peak times to ease the strain on the grid during peak usage times (OEG Ex. 1 at 7). While we recognize 10/10 Stipulation signatories state that data centers can curtail their loads during peak times, regardless, the Company still needs to invest in its transmission system to serve the incoming data center capacity. And further, the unique transient features of mobile data center facilities—where some data centers can move from location to another— necessitate a more tailored solution to prevent non-cost causing customers from paying to overbuild the Company's transmission system (Staff Ex. 1 at 17). Furthermore, AEP Ohio's position is that, unlike non-data center load, which comprises a diverse group of customer end uses, data center load cannot be naturally hedged by other industries in AEP Ohio's service territory (AEP Ex. 4 at 38-39). Thus, we recognize that data center customers pose a different type of risk, as well as an increased amount of risk. By the record evidence, we are persuaded data centers bring with them systematic, data center industry-wide risks that are not present with other types of customers. For instance, we recognize that technology breakthroughs in efficiency, market changes, and capacity underestimation are among other factors that differentiate the risk of serving a data center-only customer load from other high capacity customers (AEP Ex. 3 at 22; OEG Ex. 1 at 6). As such, AEP Ohio is faced with unprecedented load growth that will require significant EHV transmission investment to serve data center customers. As a result, the Commission finds the creation of Schedule DCT to be consistent with the Supreme Court of Ohio's ruling regarding reasonable discrimination. And with our finding, we underscore that differential treatment is not unreasonably discriminatory, such that a variation in cost recovery rates for data centers would be lawful and just in this specific situation.

{¶ 130} Relatedly, we also address the concerns regarding AEP Ohio's temporary moratorium against data center customers. The Commission understands the rationale for instituting the temporary moratorium in anticipation of this proceeding and during its pendency. The Commission is unconcerned that AEP Ohio did not conduct a study during its moratorium period, as it seems obvious that the moratorium was implemented to mitigate the Company's load from escalating too quickly, which indicates that either the Company studied or was aware of triggers for load constraint problems. As we have determined, data center load requires more nuance and a tailored solution to ensure adequate service and reliability for existing and new customers. Moreover, we reject the collective 10/10 Stipulation signatories' objections to and criticisms against this temporary measure. However, with that being said, upon the effective date of Schedule DCT, we direct

AEP Ohio to cease the moratorium and to process the queue of customer service requests. Therefore, with the lifting of the temporary moratorium, coupled with the implementation of 10/23 Stipulation's provisions, it should be abundantly apparent that the State of Ohio and its EDUs are open and willing to invest in their transmission infrastructure to serve the unique load data centers pose, while also instilling into these customers that they must make a commitment to bear a fair share of the cost of such buildouts. Moreover, the Commission has previously held that a temporary pause to process new service requests while not halting already-approved service requests was reasonable during pending Commission matters, *see In re Complaint of The Ohio Power Co v. Nationwide Energy Partners, LLC*, Case No. 21-990-EL-CSS, Opinion and Order (Sept. 6, 2023) at ¶ 278.

{¶ 131} Furthermore, Ohio is not the only state faced with this pressing question in regard to current and anticipated data center load. Idaho, Arkansas, and Wyoming—all vertically integrated states—have approved data center-tailored proposals to address the unique traits of data center and/or blockchain customers. At the outset, while we note that the Company argues that vertically integrated, bundled, states are distinguished from this jurisdiction and therefore should not be considered in this decision, we disagree to the extent that we find other state jurisdictions' decisions as insightful in determining challenges faced across the country. The Idaho Public Utilities Commission authorized IPC to establish a new customer classification applicable to high-density load customers, while praising IPC for being proactive in mitigating potential stranded asset costs to its core customers. *See Idaho Power Co. Case*, Order No. 35428 (June 15, 2022). In Arkansas, the Public Service Commission found that a proposed crypto-tariff was sensitive to the "flexible nature of cryptocurrency mining installation and the inherent unpredictability of crypto mining operations," citing to *Entergy Case*, Opinion and Order (Nov. 4, 2022) at *8. Moreover, the Wyoming Public Service Commission affirmed that there were legitimate concerns related to the questionable permanence and intense electrical demand from blockchain customers and posed concerns for existing customers being impacted by a strain that these potential customers bring. *See Black Hills Energy Case*, Memorandum Opinion, Findings, and Order

Approving Stipulation at 1-2 (July 22, 2019). While we find the abovementioned cases informative in determining this proceeding, we are confident, nonetheless, that other states have recognized a similar urgency and seriousness with regards to data center/cryptocurrency customers that required specifically tailored solutions to address state-specific challenges related to this unique customer load. Like other state commissions, this Commission determines that AEP Ohio's filing and proposal to address a data center-specific issue is proactive and takes steps to protect existing customers and non-data center customers from risks posed by future significant and unprecedented buildout required to serve the data center load.

{¶ 132} Furthermore, regarding Buckeye and AMP's arguments, the Commission agrees with AEP Ohio that the issues raised by Buckeye and AMP concern wholesale impacts that could materialize in the future and matters that are statutorily outside of this Commission's intrastate purview. *See* R.C. 4905.05. As such, we decline to consider Buckeye and AMP's proposal in this proceeding.

{¶ 133} Thus, upon review and consideration, the Commission finds that the second prong is satisfied by the 10/23 Stipulation, whereas, the 10/10 Stipulation, as package, would not benefit the ratepayers nor be in the public's interest.

3. Does the Stipulation Violate Any Important Regulatory Principle or Practice?

a. The 10/10 Stipulation

{¶ 134} The 10/10 Stipulation Signatories generally assert that the 10/10 Stipulation satisfies the third prong of the Commission's test because it comports to important regulatory principles; contains SSO provisions that do not violate Ohio law and the Commission's rules and practices; avoids issues with corporate separation policies; does not propose a discriminatory tariff; and advances key state policies as discussed above.

{¶ 135} In support of the 10/10 Stipulation, OMAEG, Enchanted Rock, OBC, and Constellation explicitly assert that this stipulation comports with the principle of cost-causation. Specifically, OMAEG indicates that the 10/10 Stipulation's provision requiring a proof of transmission constraint properly ensures that only the customers necessitating additional transmission buildout are the ones paying for it. Moreover, OMAEG highlights that AEP witness Ali confirmed that if the electrical grid has capacity available to deliver power to a customer, then the transmission buildout expansion needed to serve that customer would be lower (Tr. Vol. I at 166-167). OMAEG, thus, argues that customers who locate in areas where the service costs would be lower should not be subjected to the same financial requirements as those customers that would locate in an area with an existing transmission capacity constraint. Relatedly, both Enchanted Rock and OBC assert that the proposed 10/10 Stipulation reflects cost-causation by tying the cost-causer to the proposed Schedule EIC (One Power Ex. 5 at 13). In support, Enchanted Rock states that the 10/10 Stipulation limits the new tariff's reach by focusing on capacity constrained areas with its proof of transmission constraint requirement. Enchanted Rock insists that this approach ensures that the solution of building out more transmission infrastructure and requiring energy-intensive customers to have proper "skin in the game" would be based on true and verified need for incoming large load customers, while protecting existing customers in already constrained areas. OBC adds that OCC's witness Wilson agreed that the 10/10 Stipulation's proof transmission capacity constraint provision aligned with the principle of causation (citing Tr. Vol. IX at 1950-1953). Moreover, OBC alleges that AEP Ohio's proposed tariffs fail to acknowledge that the Company's existing transmission system can serve new loads without transmission upgrades, and would have subjected all data centers to substantial burdens, regarding whether those customers could be served with existing transmission infrastructure. (OMAEG Initial Br. at 47; Enchanted Rock Br. at 13; OBC Initial Br. at 23-24.)

{¶ 136} Relatedly, Constellation states that the specific SSO provisions in the 10/10 Stipulation promote the principle of cost-causation. Constellation witness Indukuri stated that these provisions remove large load customers from AEP Ohio's existing SSO auction processes, which would result in better outcomes for all customer classes (Tr. Vol. III at 651). Furthermore, Constellation asserts that the SSO provisions do not violate any Ohio law or run counter to Commission precedent and practice. Constellation disputes Staff witness Healey's testimony that the SSO provisions in the 10/10 Stipulation contradict recent Commission precedent. Constellation concedes that the Commission indicated in one case that it would be inclined to adopt an SSO change in a single proceeding for all electric utilities, referring to the Opinion and Order in the *FirstEnergy SSO Case*. However, Constellation points out that, as this case did not include AEP Ohio, such language is nonbinding dicta by the Commission, and that in other cases the Commission has expressed appreciation for proposals to modify the SSO. Constellation thus argues that if Staff's position holds true, then the Commission could never change its mind and that in this case, the Commission has ample record support to determine why a separate SSO procurement for large load customers is necessary. (Constellation Br. at 28-31.)

{¶ 137} AEP Ohio believes that the 10/10 Stipulation's SSO provisions would lead to unduly self-serving restrictions that reduce risk and guarantee margin for the competitive retail electricity service (CRES) provider. The Company emphasizes that Constellation witness Indukuri stated that many details for the 10/10 Stipulation SSO—including the auction rules and the boilerplate contract provisions—still needed to be determined by the Commission. And to the extent the Commission wants to address the unique SSO-related risks of data center load, the Company believes that the Commission should reject the SSO alternative in this case and take the issues up on a prospective basis in a separate docket, consistent with the settlement adopted by the Commission in *In re: Ohio Power Company* (*AEP ESP V Case)*, Case No. 23-23-EL-SSO, et al., Joint Stipulation and Recommendation (Sept. 6, 2023) at ¶ III.B.2. Moreover, AEP Ohio notes that this approach would be consistent with the recommendation in the 10/23 Stipulation to dismiss AEP Ohio's SSO proposal without prejudice. (AEP Initial Br. at 74-76.)

{¶ 138} Staff also asserts that the 10/10 Stipulation makes changes to the SSO for data centers and other large customers that are inconsistent with recent Commission precedent, which violates regulatory principles and practices. Notably, Staff states that the 10/10 Stipulation SSO provisions would be improper because Schedule EIC customers and existing data center customers over 25 MW would become ineligible for the SSO. Staff witness Healey explained in his testimony that the Commission has declined to adopt proposals that substantially alter the SSO process on a case-by-case basis and instead would likely consider SSO changes in a single proceeding for all EDUs to promote consistency and fairness (Staff Ex. 1 at 56). (Staff Initial Br. at 40.)

{¶ 139} In further support of the 10/10 Stipulation, OMAEG also contends that this stipulation properly avoids cross-subsidization between business units and upholding corporate separation policies. OMAEG emphasizes that AEP Ohio witness McKenzie testified that "[i]t cannot be determined which entity would construct any transmission investment needed to serve the more than 30,000 MW of data center projects on AEP Ohio's queue of potential future projects" (OMAEG Ex. 22; Tr. Vol. VII at 1504). OMAEG concludes that this uncertainty could mean that AEP Ohio might use revenues collected under its Schedule DCT to improperly subsidize its transmission affiliate. Accordingly, OMAEG states that such cross-subsidization violates Ohio's corporate separation policies. AEP Ohio's transmission affiliate, AEP Transco, was created in 2010 for the explicit "purpose of planning, constructing, owning, and operating transmission assets in Ohio" (Tr. Vol. I at 85). OMAEG notes "[a]ll assets owned by [AEP TransCo] must be clearly distinguishable from assets owned by AEP [Ohio]" (OMAEG Ex. 13 at 5). According to OMAEG, the provisions of the 10/10 Stipulation ensure that improper cross-subsidization does not occur, and that corporate separation is maintained. OMAEG witness Seryak endorses the 10/10 Stipulation provision that all exit fee and minimum demand charge revenues collected under Schedule EIC would go directly towards offsetting AEP Ohio's transmission costs or they would be refunded to customers with interest. Lastly, OMAEG states that while the 10/23 Stipulation has a similar provision regarding the exit fee revenues, it only provides for a potential future refund rather than requiring AEP Ohio to offset transmission costs. (OMAEG Initial Br. at 45-47.)

{¶ 140} In reply, AEP Ohio argues OMAEG's assertions regarding cross-subsidization are entirely unsupported by the record evidence and significantly minimizes the regulatory obligations that AEP Ohio follows to ensure that AEP Ohio and AEP Transco investments are treated separately. The Company emphasizes that both AEP Ohio and AEP Transco are transmission providers in Ohio and have an Open Access Transmission Tariff (OATT) in PJM. The costs of AEP Transco investments are recovered through FERC-approved OATT rates via the PJM billing process from load serving entities, including AEP Ohio. All of the OATT charges paid by AEP Ohio get passed through to its retail customers through the BTCR, and the rider is trued-up annually to ensure there is no over- or under-collection. AEP Ohio thus insists that there is no cross-subsidy—only payment of wholesale charges approved by FERC and passed through to retail customers based on charges approved by the Commission. Moreover, like the 10/10 Stipulation, the 10/23 Stipulation requires AEP Ohio to create a regulatory liability for any exit fee revenue or any revenue collected from customer collateral and, within six months of receiving such revenue, advance a proposal for Commission approval to flow funds back for the benefit of customers. The Company points out that OMAEG acknowledges that this provision will help offset any purported risk of cross-subsidization, taking issue only with the proposed timeline for implementing this proposal. AEP Ohio, thus, believes that OMAEG's assertions regarding the risk of cross-subsidization are premature and otherwise lack merit. (AEP Reply Br. at 52-53.)

{¶ 141} Lastly, as discussed in the second prong analysis, DCC, ADS, OELC, IGS, Constellation, OBC, and OMAEG also assert that the 10/10 Stipulation advances key state policies, which are enumerated in R.C. 4928.02. Several 10/10 Stipulation signatories also represent that their stipulation addresses the alleged unjust and unlawful discriminatory tariff proposed by AEP. See Order at ¶¶ 65-66.

{¶ 142} The 10/23 Stipulation signatories assert that the 10/10 Stipulation runs counter to principles of cost-causation; preempts federal issues and runs contrary to Commission practice; and violates state policies. AEP Ohio; jointly, OCC and OPAE; and Staff contend that the 10/10 Stipulation violates the principle of cost-causation. AEP Ohio explains that the purpose of the proceeding is to ensure that the customers that are causing significant transmission upgrades are the ones that pay for such costs, and that the evidentiary record supports such a mechanism. Additionally, OCC and OPAE jointly agree that the 10/10 Stipulation creates a significant disconnect between the data center cost-causers and other consumers that would be forced to pay those costs. Staff witness Healey testified that the 10/10 Stipulation has a tariff applicability threshold that is too high and allows data centers to avoid long-term contracts, exit fees, higher minimum demand charges, and minimum load ramps (Staff Ex. 1 at 53-54). And at the same time, the 10/10 Stipulation increases the risk of stranded assets, the cost of which could be imposed on other consumers because smaller data centers (under 50 MW) could request contract capacity that is far greater than their actual needs without any long-term commitment, exit fee, or minimum load ramp (OCC Ex. 2 at 8). Similarly, Staff indicates that the 10/10 Stipulation's 75 percent minimum demand allows too much of a cushion for data centers when choosing their contract capacity (Staff Ex. 1 at 54; Tr. Vol. V at 835). Staff also points out that data centers could substantially overestimate their capacity needs without material financial consequences. Staff concludes that the 10/10 Stipulation would cause overbuilding of grid infrastructure and violates the regulatory principle of cost-causation. Moreover, Staff emphasizes that the 10/10 Stipulation does not restrict customers from participating in AEP Ohio's BTCR Pilot program, which is also inconsistent with cost-causation because it could potentially allow data centers to pay little or no transmission costs (Staff Ex. 1 at 54). (AEP Ohio Reply Br. at 54; OCC/OPAE Initial Br. at 10, 29-30; Staff Initial Br. at 17, 38-39.)

{¶ 143} Additionally, OEG contends that the 10/10 Stipulation's capacity constraint provisions run contrary to Commission practice and could implicate federal preemption issues. OEG notes that the 10/10 Stipulation overlooks the interconnected nature of the transmission system, which means that a customer's usage impacts both constrained and unconstrained areas. Moreover, OEG expresses concern that the proof of capacity constraint would run afoul of federal jurisdiction over transmission. OEG explains that transmission rates fixed by FERC must be given binding effect by state utility commissions; and FERC has vested transmission planning and operation authority in PJM . Accordingly, OEG notes that high-voltage transmission projects necessary to serve AEP Ohio's data center load are subject to PJM's approval. OEG thus points out that under the 10/10 Stipulation, the burden is on AEP Ohio to provide proof of a capacity constraint at a location where a data center requests service, which is then required to be shared with the customer or its authorized third-party consultant to "verify the study's conclusions." OEG thus contends that it is unclear what happens should a customer wish to challenge the proof provided by AEP Ohio. According to OEG, such a challenge could not take place at the Commission since it does not have legal authority over the high-voltage transmission grid; and nor could the challenge take place at the Ohio Power Siting Board. (OEG Initial Br. at 22-23.)

{¶ 144} Lastly, AEP Ohio opines that the 10/10 Stipulation violates state policies, particularly R.C. 4928.02, which has been addressed under the second-prong analysis in this Order. *See* Order at ¶ 67.

b. The 10/23 Stipulation

{¶ 145} Signatories represent that the 10/23 Stipulation adheres to the principles of cost-causation and gradualism, as well as state policies detailed in R.C. 4928.02. As previously discussed, AEP Ohio represents that one of the primary purposes of this proceeding is to make sure that the cost-causers of significant costly transmission upgrades are the ones who pay for those costs. The Company insists that the record evidence sufficiently demonstrates that it is specifically data center customers causing the transmission investment. AEP Ohio thus asserts that it is both appropriate and consistent with the principles of cost-causation for Schedule DCT to apply only to new and expanding data center customers. Moreover, OCC and OPAE add that data center customers should be required to pay the minimum demand charges as specified under the 10/23 Stipulation because those who cause the costs should pay a greater share in comparison to the non-cost causers. Staff also notes that the 10/23 Stipulation requires substantial financial commitments that are tied to customers' contract capacity need and requires data centers to pay for the capacity that they forecasted to the Company (Staff Ex. 1 at 54-55). (AEP Reply Br. at 54-55; OCC/OPAE Initial Br. at 21; Staff Initial Br. at 39.)

{¶ 146} Relatedly, AEP Ohio explains that the 10/23 Stipulation furthers the principles of gradualism, particularly through its ratcheted minimum demand provisions starting at 60 percent and cap of 85 percent of contract capacity. AEP Ohio points out that compared to the Company's original proposal of 90 percent minimum demand charge, the 10/23 Stipulation's approach represents a more gradual increase in minimum demand charges for data center customers. AEP Ohio also points out that the 10/23 Stipulation's gradualistic approach has a far-reaching impact on its customers. For instance, if the data center load is an overestimate or never materializes, and the Company has already built out its transmission investment to serve the original projections, this would lead to immediate and material cost impacts on all current and prospective customers. (AEP Reply Br. at 55.)

{¶ 147} Furthermore, AEP Ohio, OCC, OPAE, and OEG urge the Commission to approve the 10/23 Stipulation because it aligns with important state policies as described in R.C. 4928.02 (OCC/OPAE Initial Br. at 24-25; OEG Initial Br. at 21). *See* Order at ¶ 97. Also, Walmart emphasizes that the 10/23 Stipulation is neither undue nor unreasonable, as it is responsive to the unique and concentrated risks inherent in load growth and service associated with data centers and cryptocurrency (Walmart Br. at 9).

{¶ 148} Parties in opposition to the 10/23 Stipulation have expressed concerns over the principle of cost-causation and the legal treatment of AEP Ohio's LOAs under the stipulation. DCC, OMAEG, OBC, and One Power explicitly argue that the 10/23 Stipulation does not comport with cost-causation principles. Notably, DCC represents that the 10/23 Stipulation proposes excessive minimum demand charges that are not anchored in any quantitative analysis or estimate of the incremental costs associated with data center customer load. DCC claims that Mr. Higgin's quantitative analysis—the only one in the evidentiary record—demonstrates that the 10/23 Stipulation's minimum demand charges are far higher than necessary to ensure that data center revenue covers the incremental costs of the transmission infrastructure required to serve them. Relatedly, OBC notes that AEP Ohio witness McKenzie and OEG witness Wellborn both confirmed during hearing that there is non-constrained transmission capacity in other parts of Ohio outside of central Ohio (Tr. Vol. VII at 1314-1315, 1483). OBC and One Power accordingly argue that the 10/23 Stipulation violates cost-causation because it improperly applies to all data center customers with loads over 25 MW regardless of whether an individual customer creates the need for transmission upgrades. Relatedly, OMAEG asserts that the 10/23 Stipulation fails to recognize that customers locating in areas with lower service costs should not be subjected to the same financial burdens and costs as customers that choose to locate in areas with an existing transmission capacity constraint. (DCC Initial Br. at 66; OBC Initial Br. at 37-38; One Power Initial Br. at 27; OMAEG Initial Br. at 47.)

{¶ 149} Furthermore, One Power argues that the Company's current practice of requiring customers to sign LOAs that require credit support and reimbursement for 100 percent of AEP Ohio's buildout costs violates Ohio law, the Commission's rules, and AEP Ohio's tariff. One Power states that the law only obligates a customer to pay a portion of transmission and distribution line extension costs, such that the Company is responsible for a majority of the buildout costs. One Power insists that neither the Commission's rules nor AEP Ohio's tariffs allow AEP Ohio to require customers to provide any sort of cost reimbursement. One Power thus states that if the Company wanted to modify its line extension tariff to address reimbursement and credit support obligations for customers, then AEP Ohio should do so in a proper filing and not through the 10/23 Stipulation. (One Power Initial Br. at 28-29.)

{¶ 150} In reply to One Power's allegations, the Company asserts that its usage of LOAs has been a longstanding practice and is consistent with Ohio law, Commission precedent, and the Company's tariffs. Under AEP Ohio's tariffs, the Company can require written agreements prior to providing service to a customer, citing to 5th Revised Sheet No. 220-3, Schedule GS, requiring electric service contracts if certain conditions are met; 1st Revised Sheet No. 103-2, Par. 3, "Written agreements will be required prior to providing service if stipulated in the applicable rate schedule or the customer has unusual or special service characteristics." One of the written agreements AEP Ohio has historically required is the LOA. The LOAs indicate what the Company expects to pay to build new distribution and transmission equipment to serve customers, wherein the customer shall reimburse AEP Ohio for its buildout costs if the customer cancels its project or delays the project past a specific date. AEP Ohio underscores that LOAs prevent the unfair shifting of costs associated with stranded investments made to serve abandoned projects. According to the Company, LOAs enable a project that requires substantial investment to proceed without undue delay associated with executing an ESA at project inception before all engineering studies may be complete. The Company insists that maintaining Ohio's longstanding LOA/ESA process preserves the abovementioned essential benefits for AEP Ohio, data centers, and other customers. (AEP Ohio Reply Br. at 51.)

c. Conclusion

{¶ 151} Regarding the third prong, the Commission determines that the 10/23 Stipulation meets this criterion, while the 10/10 Stipulation does not. Overall, we reiterate our determination that the 10/23 Stipulation facilitates specific state policies under R.C. 4928.02 and is properly tailored to address a pressing threat to electric system reliability and customers' service. Moreover, we find that the 10/23 Stipulation facilitates and promotes the important regulatory principles of cost-causation and gradualism, as the 10/10 Stipulation affords too much regulatory uncertainty. The 10/23 Stipulation properly assigns the cost burden of developing required transmission in response to the incoming data center load.

{¶ 152} The Commission recognizes that both 10/10 Stipulation and 10/23 Stipulation signatories assert that their respective stipulations comply with the principle of cost-causation. The principle of cost-causation is an important regulatory principle that prioritizes the assignment of costs to the entity or group of entities that cause the cost on the system. *In re Duke Energy Ohio, Inc.*, Case Nos. 22-507-GA-AIR, et. al, Opinion and Order (Nov. 1, 2023) at ¶ 67; see also *In re Ohio Power Co.*, Case No. 14-1158-EL-ATA, Opinion and Order (Apr. 27, 2016) at 11; *In re Duke Energy Ohio, Inc.*, Case Nos. 21-887-El-AIR, et. al, Opinion and Order (Dec. 14, 2022) at ¶ 153. We determine that the 10/23 Stipulation strikes the proper balance with ensuring that the data center cost-causers are responsible for the correct share of transmission buildout costs. The 10/10 Stipulation would lead to an imbalanced regulatory environment where the main cost-causers would not be assigned enough of the financial burden for costly transmission infrastructure buildout. As we have thoroughly contemplated above, the Company has demonstrated in the record that within the next five years, AEP Ohio grid's reliability and stability—including voltage outages and violations—will be challenged by an influx of data centers, which involves upwards of an additional 30,000 MW added to the grid by 2030 (Sidecat Ex. 10; Tr. Vol I at 115, 119, 123, 187, 226-235; AEP Ex. 2 at 3-5). As such, any arrangement assigning less than the proper share of costs on these data center parties that could disrupt the Ohio grid would be in direct contradiction of cost causation. The Commission finds Staff witness Healey's testimony insightful, as he explains that the 10/10 Stipulation's tariff applicability threshold is too high and allows data centers to avoid long-term contracts, exit fees, higher minimum demand charges, and minimum load ramps (Staff Ex. 1 at 53-54). We recognize the 10/23 Stipulation signatories' concerns that this proceeding is to address a surge in demand for electrical service from unique energy-intensive customers, while also preventing other ratepayers from shouldering an unfair share of the costs of significant transmission investment that has nothing to do with them. In our review, we agree that the 10/10 Stipulation as a package offers too many opportunities for the energy-intensive data centers to avoid their responsibility as the main cost-causers for the construction and integration of new AEP Ohio transmission facilities. Moreover, the Commission also notes that the 10/23 Stipulation's provisions are not a stark departure from those proposed in the 10/10 Stipulation, which DCC even conceded in its brief.[8] Yes, the differences between the two stipulations are a matter of degree in some provisions. However, the 10/23 Stipulation is the only agreement that ensures the cost-causers are held accountable for the significant investments the Company would have to construct to ensure that all of its customers receive safe and reliable electrical service.

{¶ 153} The Commission, therefore, does not find compelling the arguments from 10/10 Stipulation signatories that the 10/23 Stipulation unfairly and improperly imparts too many upfront costs onto data centers without concrete proof of AEP Ohio's transmission capacity. The Commission reminds the parties that the grid is interconnected. Thus, the fact that the capacity constraint is mainly located in central Ohio should not have a bearing on the merits of the 10/23 Stipulation's alignment with cost-causation. As such the transmission capacity constraint provision in the 10/10 Stipulation is not a catchall provision that ties the 10/10 Stipulation to cost-causation.

{¶ 154} The Commission also recognizes that the 10/23 Stipulation incorporates the principle of gradualism by implementing a progressive minimum demand requirement starting at 60 percent and limited to 85 percent of contract capacity. We note that under gradualism, rates are to be increased gradually over time to avoid customer rate shock; and we determine that this is precisely what the 10/23 Stipulation ensures for data center customers. Moreover, the Commission agrees that all of AEP Ohio customers are implicated in this proceeding. If safeguards are not implemented, like the 10/23 Stipulation's minimum demand requirement, then non-data center customers could experience a significant rate shock if the Company built out its transmission grid and the data center load ends up being an overestimate or does not materialize at all.

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8 "The difference between the two stipulations on each of the terms listed above is a matter of degree, and not a categorical difference" (DCC Reply Br. at 25).

{¶ 155} Further, the Commission is not swayed by Constellation's arguments that the SSO provisions in the 10/10 Stipulation promote the principle of cost-causation. As we have noted in previous cases, should the Commission be inclined to consider and adopt SSO changes, it should be done so with all of the electric utilities to ensure fairness and consistency amongst the regulated EDUs. *See FirstEnergy SSO Case* Opinion and Order at ¶ 77; *AEP ESP V Case,* Opinion and Order (Apr. 3, 2024) at ¶ 82; *In re Dayton Power & Light Co. d/b/a AES Ohio*, Case No. 22-900-EL-SSO, et al., Opinion and Order (Aug. 9, 2023) at ¶ 247. Furthermore, the Commission is not satisfied that the proposed SSO provisions in the 10/10 Stipulation have been thoroughly considered by the relevant parties to implement such a change at this time. As Staff points out, Schedule EIC customers and existing data center customers over 25 MW would become ineligible for the SSO and be subject to a proposed new default service program that was adopted in a manner inconsistent with recent Commission precedent. Moreover, AEP Ohio withdrew its SSO provisions from its application and made it abundantly clear that should it wish to propose a modified SSO process, it would do so in a separate proceeding. The Commission agrees that a proposal to materially alter the SSO default process should be analyzed carefully by relevant intervening parties, some of which are not parties to this proceeding, including the other three EDUs in the state, and that a full evidentiary record on this topic alone, would be more appropriate.

{¶ 156} Regarding OMAEG's assertions over improper cross-subsidization, the Commission finds these concerns to be premature and without merit. We recognize that Mr. McKenzie testified that it could not be determined which entity between AEP Ohio and AEP Transco would construct any of the transmission buildout necessary to accommodate data center customers (Tr. Vol. VII at 1504). However, OMAEG's allegations completely ignore the fact that this Commission approved the creation of AEP Transco within strict regulatory confines to prevent any such improper cross-subsidization between the two entities. For instance, costs of AEP Transco investments are recovered through FERC-approved OATT rates via the PJM billing process for load serving entities and allocated costs from outside the AEP Zone; whereas, all of the OATT charges paid by the Company get passed through to its retail customers through the BTCR, which is trued up with the Commission on an annual basis or by filing a complaint pursuant to R.C. 4905.26. Thus, AEP Ohio and AEP Transco investments are treated separate from one another. Therefore, the Commission rejects OMAEG's arguments and agree that the 10/23 Stipulation on its face does not present any concerns regarding the corporate separateness of AEP Ohio and AEP Transco. Moreover, should OMAEG wish to challenge any perceived cross-subsidization issues, it has the opportunity to do so, in those annual true-up proceedings. Further, the Commission affirms the 10/23 Stipulation's commitment that AEP Ohio will create a regulatory liability for exit fee or customer collateral revenue and, within six months of receiving such revenue, advance a proposal for Commission approval to flow funds back to customers. We also note that the 10/10 Stipulation proposed a similar provision, which indicates that signatories to both stipulations can agree that this kind of provision will help offset any purported risk of cross-subsidization.

{¶ 157} Lastly, the Commission reiterates its above findings that the 10/23 Stipulation complies with important state policies listed under R.C. 4928.02 and that it is not an unduly discriminatory tariff. In addition to the 10/23 Stipulation's adherence to and promotion of R.C. 4928.02, the Commission further emphasizes the uniqueness and far-reaching impact this case will have on the state. Thus, in comparison to the 10/10 Stipulation, which favors weaker commitments from incoming data center customers, the 10/23 Stipulation appropriately balances the encouragement of incoming data center investment from global companies that will significantly alter Ohio's grid for years to come, with protecting non-data center customers from service disruption. As such, the 10/23 Stipulation does not unduly discriminate against data center customers and rather is responsive to the unique and particular risks associated with serving data center customers on AEP Ohio's existing transmission grid. Therefore, consistent with our findings above, the 10/23 Stipulation meets the third prong of the Commission's stipulation test; and the 10/10 Stipulation does not present a package that is in the public interest or benefits ratepayers, such that it did not meet second prong of this Commission's test, and as such does not comply with important regulatory principles and does not advance state policy objectives set forth in R.C. 4928.02.

V. Conclusion

{¶ 158} Accordingly, based on the foregoing, the Commission finds that the 10/23 Stipulation should be adopted, as modified by this Order. With this finding, as qualified above, the Commission directs AEP Ohio to file updated tariffs for Schedule DCT, under which applicable data centers shall be subject to the specified load ramp period, longer contract terms, adjusted minimum demand charges, collateral requirement, capacity reassignment limitations, and new service enrollment process, amongst other 10/23 Stipulation provisions. Furthermore, AEP Ohio is directed to cease its temporary service moratorium, consistent with this Order.

VI. Findings of Fact and Conclusions of Law

{¶ 159} AEP Ohio is a public utility as defined in R.C. 4905.02 and, as such, is subject to the jurisdiction of this Commission.

{¶ 160} On May 13, 2024, AEP Ohio filed an application, pursuant to R.C. 4909.18, requesting approval of tariffs to establish two new customer classifications.

{¶ 161} A technical conference was held on May 30, 2024 at the Commission's offices.

{¶ 162} On June 25, 2024, interested stakeholders filed initial comments and on July 8, 2024, reply comments were timely filed.

{¶ 163} By Entry dated October 3, 2024, the ALJ granted intervention to Ohio Energy Group; IGS; ADS; DCC; Walmart; Google; Enchanted Rock; OMAEG; OCC; One Power; RESA; Constellation; Microsoft; Sidecat; OPAE; OELC; OBC; Calpine; and jointly, Buckeye and AMP.

{¶ 164} On October 10, 2024 ADS; OELC; Enchanted Rock; RESA; Sidecat; Microsoft; IGS; Constellation; OMAEG; DCC; Google; OBC; and One Power filed a stipulation, purporting to resolve all issues in this proceeding.

{¶ 165} On October 23, 2024, AEP Ohio, Staff, OCC, OPAE, OEG, and Walmart filed a stipulation, purporting to resolve all issues in this proceeding.

{¶ 166} An evidentiary hearing in this proceeding commenced on December 3, 2024 and concluded on January 17, 2025.[9]

{¶ 167} On January 3, 2025, a local public hearing was held, as scheduled, at the Commission's offices.

{¶ 168} The Commission finds that the 10/23 Stipulation meets the three criteria for approval of a stipulation, is reasonable, and should be adopted.

{¶ 169} AEP Ohio is authorized to submit final revised tariffs for the Commission's review. The new tariffs will not become effective until they are final filed with the Commission pursuant to future Commission order.

VII. ORDER

{¶ 170} It is, therefore,

{¶ 171} ORDERED, That the 10/23 Stipulation be approved and adopted, subject to modifications consistent with this Order. It is, further,

{¶ 172} ORDERED, That AEP Ohio is authorized to file in final form two complete copies of tariffs consistent with this Opinion and Order. One copy shall be filed with these case dockets, and one copy shall be filed in the Company's TRF docket. The Company shall

9 *See* Order at ¶¶ 11-13, regarding extenuating circumstances for which the evidentiary hearing was continued on December 10, 2024, to January 6, 2025.

also update its tariffs previously filed with the Commission's Docketing Division. It is, further,

{¶ 173} ORDERED, That AEP Ohio shall notify all affected customers of the tariffs via bill message or bill insert within 30 days of the effective date of the revised tariffs. A copy of this customer notice shall be submitted to the Commission's Service Monitoring and Enforcement Department, Reliability and Service Analysis Division, at least ten days prior to its distribution to customers. It is, further,

{¶ 174} ORDERED, That the effective date of the revised tariffs shall be a date not earlier than the date of this Opinion and Order and the date upon which two complete copies of the final tariffs are filed with the Commission. It is, further,

{¶ 175} ORDERED That One Power's motion to dismiss be denied as stated in Paragraph 25. It is, further,

{¶ 176} ORDERED, That a copy of this Opinion and Order be served upon all interested persons and parties of record.

COMMISSIONERS:
Approving:
Jenifer French, Chair
Daniel R. Conway
Lawrence K. Friedeman
Dennis P. Deters
John D. Williams

IMM/DMH/lga/dr

BOUNDLESS ENERGY™

Legal Department

American Electric Power
1 Riverside Plaza
Columbus, Ohio 43215-2373
AEP.com

July 11, 2025

Tanowa Troupe
Docketing Division
Public Utilities Commission of Ohio
180 East Broad Street
Columbus Ohio 43215-3793

Steven T. Nourse
Vice President – Legal
(614) 716-1608 (P)
(614) 716-2014 (F)
stnourse@aep.com

Re: *In the Matter of the Application of Ohio Power Company for New Tariffs Related to Data Centers and Mobile Data Centers,* Case No. 24-508-EL-RDR

Dear Ms. Troupe:

Enclosed are Ohio Power Company's compliance tariffs, which are being filed in accordance with the Commission's Opinion and Order dated July 9, 2025 in the above-captioned case. In accordance with the modification to the October 23, 2024 Joint Stipulation and Recommendation (10/23 Stipulation) adopted by the Commission in Paragraph 126 of the Opinion and Order, a definition of the term "customer" has been added to the collateral requirements section of the tariff to clarify that the term "customer" in that section includes a financial sponsor that co-signs the agreement with AEP Ohio. The only other substantive change is eliminating the separate rate zones that have been eliminated since the time of the 10/23 Stipulation being filed. Consistent with Paragraph 169 of the Opinion and Order, the Company requests approval of the enclosed compliance tariffs.

Upon approval of the compliance tariff and consistent with Paragraph 130 of the Opinion and Order, the temporary moratorium will end and going forward AEP Ohio will serve all new data center load in its service territory based on the terms and conditions in the new tariff using the process for signing up new data center load in Paragraph III.F of the 10/23 Stipulation.

Thank you for your attention to this matter.

Respectfully Submitted,

cc: Parties of Record

P.U.C.O. NO. 21

SCHEDULE DCT
(Data Center Tariff)

Definitions

For purposes of this schedule:

"Contract" means the service agreement entered into by the customer and the Company in accordance with this schedule.

"Contract Capacity" means the mutually agreed amount of monthly peak load requirements for each month during the remaining term after the Load Ramp Period as set forth in the contract for service, whereby the Company agrees to provide all of the components of retail electric service (which could include either default SSO supply or access to CRES provider supply of generation service) subject to the terms and conditions in its tariffs and the customer agrees to purchase service at that level for the stated term of the contract under the same terms and conditions."

"Data Center" means a centralized facility (a) used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information through the use of computer systems, servers, networking equipment, and related components that (b) has an aggregate monthly maximum demand of greater than 25,000 kW. Unless otherwise specified, the term "Data Center" shall include "Mobile Data Center."

"Mobile Data Center" means a centralized facility (a) used primarily or exclusively for electronic information services such as the management, storage, processing, and dissemination of electronic data and information (including mining of cryptocurrency) through the use of computer systems, servers, networking equipment, and related components that (b) has an aggregate monthly maximum demand of greater than 25,000 kW and has load that is portable and/or distributable, including but not limited to structures that are not affixed to the ground or are easily removed from a location.

"Single Location" refers to an area that is owned, operated, or leased by the Data Center customer with the metering point for the customer's metering point. A contiguous lot (or lots) to the area with the customer's metering point may be considered the customer's premises regardless of easements, public thoroughfares, transportation rights-of-way, or utility rights-of-way, so long as it would not create an unsafe or hazardous condition.

"Load Ramp Contract Capacity" means the mutually agreed monthly peak load requirements associated with the Load Ramp Period. The Load Ramp Contract Capacity shall not be less than:

In Year 1, 50% of Contract Capacity.
In Year 2, 65% of Contract Capacity.
In Year 3, 80% of Contract Capacity.
In Year 4, 90% of Contract Capacity.

"Load Ramp Period" refers to the time of commencement of service until the customer reaches full contract capacity, which shall not exceed four years.

Filed pursuant to Order dated ~~____________~~ July 9, 2025 in Case No. 24-508-EL-ATA

Issued: ____________ Effective: ____________

Issued by
Marc Reitter, President
AEP Ohio

"Existing Load" means Data Center load for which a letter of agreement or electric service agreement has already been signed by the effective date of Schedule DCT.

"New Load" means Data Center load for which a letter of agreement or electric service agreement has not been signed before the effective date of Schedule DCT.

Availability of Service

Service pursuant to this schedule is available for general service to customers that operate a Data Center that will use, within the initial contract term, a monthly maximum demand of greater than 25,000 kW at a Single Location or an aggregated Total Customer Contract Capacity in Service Territory of greater than 25,000 kW as described below.

Customers qualifying for this schedule that execute an electric service agreement with the Company or expand their current contracted capacity after the effective date of this tariff are required to take service under this schedule and will not be permitted to take service under other general service tariffs.

Schedule DCT does not apply to Existing Load above 25,000 kW that has already signed a letter of agreement or electric service agreement by the effective date of Schedule DCT, so long as the Existing Load does not expand by more than 25,000 kW above the contracted capacity under the existing electric service agreement following the effective date of Schedule DCT. Schedule DCT will apply to an Existing Load that signs a new electric service agreement to expand its Existing Load by more than 25,000 kW of New Load above the contract capacity under the existing electric service agreement after the effective date of Schedule DCT. At the customer's request, AEP Ohio will use reasonable efforts to separately meter the New Load to which Schedule DCT applies, but it may not be technically feasible to do so. If it is technically feasible to separately meter, the customer will pay all costs reasonably incurred by AEP Ohio to complete such separate metering. If the load is not separately metered, then the Existing Load will lose its Existing Load status and become subject to Schedule DCT.

If the customer facility operates one or more Data Centers with a monthly maximum demand of greater than 25,000 kW and has non-Data Center load (that would otherwise be billed under the General Service or other applicable Schedule) at a Single Location, Schedule DCT will apply to all electric distribution service to that customer, provided, however, that the customer shall have the option of separately metering its Data Center and non-Data Center loads (if technically feasible) and paying for those loads through separate customer accounts. In such situation, the customer shall be responsible for all metering and other costs necessary to separate its load into separate customer accounts.

The terms and conditions of service under this this schedule shall apply upon a request for service by an eligible customer but service to customers under this schedule will not commence until the Company has sufficient capacity to meet the contractual load requirements.

With Commission approval, service to a Schedule DCT customer may be suspended by AEP Ohio if customer usage exceeds its Contract Capacity by more than 1,000 kW. If the Company determines that additional capacity is available from AEP Ohio to serve additional load at the customer site, the Company

P.U.C.O. NO. 21

SCHEDULE DCT
(Data Center Tariff)

may also seek mutual agreement to adjust the Contract Capacity and reserves the right to raise the issue before the Commission if there is no agreement.

Monthly Rate

Schedule Code	Service Voltage	Distribution Demand Charge ($/kW)	Excess Reactive Demand ($/kVA)	Customer Charge ($)
~~###~~296,796	Secondary	$7.01	$1.25	$9.40
~~###~~295,795	Primary ~~Ohio Power Rate Zone~~ ~~Columbus Southern Power Rate Zone~~	$~~6.46~~6.33 ~~$6.17~~	$1.21 ~~$1.21~~	$138.50 ~~$138.50~~

Schedule Code	Service Voltage	Distribution Demand Charge ($/kW)	Excess Reactive Demand* ($/kVAR)	Customer Charge ($)
~~###~~297,797	Transmission	--	$0.70	$3,600

*For each kVAR of reactive demand, leading or lagging, in excess of 50% of the kW metered demand.

Minimum Charges

The minimum monthly charge under this schedule shall be the sum of the customer charge, the product of the distribution demand charge and the monthly distribution billing demand, and all Commission-approved riders shown on Sheet Number 104-1.

Monthly Billing Demand

Billing demand in kW shall be taken each month as the single highest 30-minute integrated peak in kW as registered during the month by a 30-minute integrating demand meter or indicator, or at the Company's option, as the highest registration of a thermal-type demand meter. The customer will have no more than the Load Ramp Period to reach full contract capacity, during which time monthly billing demand shall not be less than 85% of the customer's Load Ramp Contract Capacity. After the Load Ramp Period, monthly billing demand established hereunder shall not be less than the greater of (a) 85% of the customer's highest previously established monthly billing demand during the past 11 months or (b) the customer's "Minimum Demand" as set forth below:

Total Customer Contract Capacity in Service Territory	Minimum Demand

Filed pursuant to Order dated ~~______________~~ July 9, 2025 in Case No. 24-508-EL-ATA

Issued: ______________ Effective: ______________

Issued by
Marc Reitter, President
AEP Ohio

SCHEDULE DCT
(Data Center Tariff)

25,001 kW to 75,000 kW	15,000 kW plus 85% of marginal amount over 25,000 kW
75,001 kW and above	57,500 kW plus 100% of marginal amount over 75,000 kW; provided, however, that the minimum demand will not exceed 85% of the total contract capacity.

All New Loads of affiliated companies and companies with common ownership greater than 25,000 kW will be considered in the aggregate for purposes of determining the "Total Customer Contract Capacity in Service Territory" and calculating the "Minimum Demand" in the chart above that will be included for the full term of each Contract for New Load under this Schedule DCT. Existing Load will not be considered as part of the "Total Customer Contract Capacity in Service Territory." All affiliated New Load will be stacked in order of the energization date so the Minimum Demand can be applied based on multiple Contracts, as applicable. If there are multiple New Loads at a Single Location of less than 25,000 kW (but the aggregate total load is greater than 25,000 kW), all of those New Loads will be subject to Schedule DCT.

Unless otherwise mutually agreed by the Company and the customer, the customer shall be billed under the provisions of this tariff using the Contract Capacity during all months of the initial term of contract should the customer fail to energize service. The monthly billing demand defined hereunder shall apply for purposes of billing under all applicable riders, regardless of any conflicting provision in the rider.

Delayed Payment Charge

Bills are due and payable in full by mail, checkless payment plan, electronic payment plan or at an authorized payment agent of the Company within 21 days after the mailing of the bill. On all accounts not paid by the due date, an additional charge of 2.5% of the unpaid balance will be due.

Applicable Riders

Monthly Charges computed under this schedule shall be adjusted in accordance with the Commission-approved riders on Sheet Number 104-1 that apply to Demand Metered commercial and industrial service. Nothing in this tariff excepts eligible customers from other riders or applicable tariffs.

Generation Service

Customers receiving service under this schedule may select competitive service from a CRES Provider or Standard Offer Service. The Company requires that Company-owned metering be installed to monitor the customer's load.

Transmission Service

Customers receiving service under this schedule shall pay the charges established for Demand Metered Service under the Basic Transmission Cost Rider ("BTCR"). New Loads receiving service under this schedule are not eligible to participate in the 1CP or 6CP BTCR Programs or any successor programs.

SCHEDULE DCT
(Data Center Tariff)

Terms of Contract

Contracts under the Schedule shall be made for an initial period of not less than the Load Ramp Period plus 8 years. By way of example, the initial period of a Contract for a Data Center with a 4-year Load Ramp Period will be 12 years. If electric infrastructure is not in place to serve the customer by the Contract's estimated in-service date, the customer may petition the Commission for an adjustment to the contract term based on the facts and circumstances presented at that time (but will otherwise remain the Load Ramp Period plus 8 years).

After the initial term, Contracts shall remain in effect unless terminated by either party by providing written notice to the other party no later than three (3) years prior to the requested date of termination. After the initial term, either party may request a modification to the Contract Capacity by providing written notice to the other party no later than three (3) years prior to the requested modification date. During the initial term of the Contract, the customer will be financially responsible to pay the minimum charges regardless of the customer choosing to curtail, reduce, suspend, or terminate service. If after completion of the fifth year of the Contract after the Load Ramp Period the customer chooses to pay an exit fee equal to minimum charges for 36 months after notice of termination, the customer can thereafter terminate the contract. By way of example, a customer with a 3-year Load Ramp Period may pay the exit fee and terminate the contract only after Year 8 of the Contract.

The customer shall agree with the Company in advance its Load Ramp Contract Capacity and a final Contract Capacity value to be used for the remaining initial term of the contract. A new contract will be required for any load additions in excess of 100 kW.

The Company shall not be required to supply capacity in excess of the Contract Capacity except by mutual agreement.

Nothing in this Schedule limits the requirement that a customer sign a Letter of Agreement for network and customer specific investment prior to energization or Contribution in Aid of Construction agreement for customer-specific investment.

To sign a contract under this Schedule, the customer must designate a specific site at which its Data Center project will be constructed and served by the Company, and the customer must own or have the exclusive right to use the land for this purpose.

Collateral Requirement

For purposes of the collateral requirement under this section, "customer" shall include both the customer and the customer's financial sponsor as long as the sponsor is a co-signer on the contract with AEP Ohio
The customer, if not having both (a) a credit rating of at least A- from S&P Global Inc. ("S&P") and A3 from Moody's Corporation ("Moody's") and (b) cash and cash equivalents on an audited balance sheet prepared in accordance with Generally Accepted Accounting Principles ("GAAP") ("Liquidity") greater than ten times the Collateral Requirement, must provide a guarantee or collateral at the time of signing the contract equal to 50% of the total minimum charges for the full term of the contract ("Collateral

Requirement"), calculated based on AEP Ohio's rates in effect at the time the Collateral Requirement is provided. The Collateral Requirement must be provided in one or more of the following forms:

1. A guarantee from the ultimate parent or a corporate affiliate of the customer for the full Collateral Requirement, so long as the guarantor has both (a) a credit rating of at least A- from S&P and A3 from Moody's and (b) Liquidity greater than ten times the Collateral Requirement; or

2. A standby irrevocable letter of credit ("Letter of Credit") for the full Collateral Requirement. The Letter of Credit must be issued by a U.S. bank or the U.S. branch of a foreign bank, which is not affiliated with the customer or its guarantor, with a Credit Rating of at least A- from S&P and A3 from Moody's. Such security must be issued for a minimum term of 360 days. The customer must cause the renewal or extension of the security for additional consecutive terms of 360 days or more no later than 30 days prior to each expiration date of the security. If the security is not renewed or extended as required herein, the Company will have the right to draw immediately upon the Letter of Credit and be entitled to hold the amounts so drawn as security. The Letter of Credit must be in a format acceptable to and approved by the Company.

3. Cash for the full Collateral Requirement.

The amount of the Collateral Requirement will be reduced by one year's minimum charges for each year the customer is energized and makes on-time electric service payments under the contract.

If the financial condition of the customer or guarantor changes – or market conditions (including ownership/structural changes) change – over the term of the contract, the Company may request updated information to reevaluate the customer and its collateral requirements, which may be adjusted accordingly.

Customer-Owned Generation and Emergency Conditions

Consistent with Ohio Administrative Code Chapter 4901:1-22, Schedule DCT Customers shall enter into an interconnection agreement between the Company and the Customer in advance of connecting any source of power other than the delivery point specified in the Contract. Emergency or backup generation that is not designed to operate in parallel with the Company's system is not subject to the additional requirements in this section.

With Commission approval, service to any customer using behind-the-meter generation to serve some or all of its demand that elects not to offset its Contract Capacity with output from its behind-the-meter generation may be suspended by AEP Ohio if customer usage exceeds its Contract Capacity by more than 1,000 kW.

If the customer elects to use its behind-the-meter generation to offset the customer's Contract Capacity (either in initially establishing service or in the context of a subsequent load expansion or behind-the-meter generation expansion at the same site, as reflected in a new or updated Contract Capacity), the following requirements will apply. In order to ensure that the Customer's election to net does not result in it exceeding its Contract Capacity, equipment must be in place and maintained through the term of the

P.U.C.O. NO. 21

SCHEDULE DCT
(Data Center Tariff)

Electric Service Agreement to instantaneously curtail load equal to or greater than the behind-the-meter generation output, subject to the then-current technical requirements of the transmission provider. If the equipment fails and results in the customer exceeding its Contract Capacity, the Company reserves the right to raise before the Commission any unresolved reliability or safety concerns based on the facts and circumstances presented at that time.

Nothing in this paragraph affects AEP Ohio's right to disconnect or curtail load in accordance with Section 26 of the Terms and Conditions of Service in the Company's tariff and Ohio Administrative Code 4901:1-10-16.

Special Terms and Conditions

This schedule is subject to the Company's Terms and Conditions of Service.

Customers served under this tariff agree to written attestation as part of its Contract that the customer will follow all applicable technical operating requirements, such as not intentionally or unintentionally cycling load in a way that creates an imbalanced or unacceptable system frequency, and other requirements that will be maintained and periodically updated for the safety of the larger system. Upon detection of any activities outside of the technical requirements, the Company has the right to disconnect.

With Commission approval, service may be suspended by AEP Ohio to a customer under Schedule DCT (including a customer with behind-the-meter generation that has elected not to net its Contract Capacity) if the customer usage exceeds its Contract Capacity by more than 1,000 kW. If additional capacity is available at the customer site, the Company may also seek mutual agreement to adjust the Contract Capacity and reserves the right to raise the issue before the Commission if there is no resolution. Nothing in this paragraph affects the provision above regarding behind the-meter generation or is intended to preclude the Company from disconnecting service or curtailing load to a Schedule DCT customer without Commission approval in accordance with Section 26 of the Terms and Conditions of Service in the Company's tariff and Ohio Administrative Code 4901:1-10-16.

Prior to receiving service, Mobile Data Center customers will be required to provide a sworn statement, under penalty of perjury, that neither the customer nor its corporate parent or affiliates are affiliated with or acting on behalf of any foreign adversary as defined in 15 C.F.R. § 7.4. If AEP Ohio has a good faith belief that a Mobile Data Center customer has provided false information in response to this requirement, AEP Ohio has the right to immediately disconnect service to the Mobile Data Center permanently or until adequate proof is shown to satisfy AEP Ohio that the Mobile Data Center customer meets this requirement.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

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in

Case No(s). 24-0508-EL-ATA

Summary: Tariff In Response to the July 9, 2025, Opinion and Order. electronically filed by Mr. Steven T. Nourse on behalf of Ohio Power Company.

Congress of the United States
Washington, DC 20510

April 4, 2025

The Honorable Robert F. Kennedy Jr.
Secretary of Health and Human Services
200 Independence Avenue SW
Washington, DC 20201

Dear Secretary Kennedy,

We write to you regarding the administration's decision to eliminate the entire staff responsible for administering the Low Income Home Energy Assistance Program (LIHEAP) at the Department of Health and Human Services (HHS).

As you know, on April 1, 2025, approximately 10,000 employees at HHS received notice that they had been placed on administrative leave until June 2, 2025, after which their position would be terminated. These layoffs included the entirety of the team at the Office of Community Services within the Office of the Administration for Children and Families, which leads dozens of programs, including LIHEAP. It has been reported that these terminations were also a surprise to the state-level LIHEAP administrators who distribute the program's aid dollars to families in their communities.

This program is vital for millions of families, and in fact is oversubscribed. More than 25 million American households report foregoing food and medicine to pay their energy bills, and of those, 7 million households report that they face that decision every month.[1] LIHEAP benefits target households who need the assistance the most, particularly those that have a high home energy burden and or have household members who are elderly, disabled, and or young children. In Fiscal Year 2023, 2.1 million recipient households included an individual with a disability, 996,000 households included a young child, and 2.4 million households included an elderly adult.[2] The program is a lifeline for American families who struggle to heat their home in the winter and cool their homes in the summer.

Though the staff of 25 employees account for only a small fraction of the announced layoffs, they are responsible for administering billions of dollars each year to support millions of families across the nation in heating and cooling their homes. Each year, all 50 states, the District of Columbia, five U.S. territories, and about 150 tribes apply for funds through the HHS division that you have eliminated. In Fiscal Year 2023, nearly 6 million households received LIHEAP assistance, and LIHEAP restored power or prevented disconnections over 2.7 million times for

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[1] https://www.npr.org/2018/09/19/649633468/31-percent-of-u-s-households-have-trouble-paying-energy-bills
[2] https://acf.gov/ocs/fact-sheet/liheap-fact-sheet

American families because the staff within the Office of Community Services processed each state and territory's application for funds.[3]

Moreover, LIHEAP supported 1.4 million households in crisis assistance.[4] This is not funding that can wait; a team must be in place to support this program's work. By removing the staff responsible for managing this vital program, this administration has directly burdened the families in our country who need our support most.

We are also concerned that without any federal employees working to support LIHEAP, there will be delays in the release of the remaining $378 million in the FY 25 appropriation for LIHEAP. These funds are needed to help provide assistance for families who fell behind on their winter heating bills due to unexpected emergencies, summer cooling to address extreme temperatures, and weatherization.

Gutting this program's staff is a reckless and irresponsible decision which may cost these families' lives. We urge you to immediately reverse this decision and do all you can to support the work of this vital program.

Sincerely,

Chris Pappas

Chris Pappas
Member of Congress

Angie Craig

Angie Craig
Member of Congress

Jared F. Golden

Jared Golden
Member of Congress

Marilyn Strickland
Member of Congress

Eric Sorensen
Member of Congress

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[3] https://acf.gov/ocs/fact-sheet/liheap-fact-sheet ; https://www.aga.org/natural-gas/affordable/liheap/#:~:text=LIHEAP%20restored%20power%20or%20prevented,families%20avoid%20dangerous%20heating%20practices.

[4] https://acf.gov/ocs/fact-sheet/liheap-fact-sheet

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Member of Congress

John B. Larson
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Member of Congress

Nydia M. Velázquez
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Florida Trend
FLORIDA'S BUSINESS AUTHORITY

July 14, 2025

SHARE:

ARTICLES

Florida's Top 10 Private Landowners

Mike Vogel
| 1/16/2025

No. 1

FARMLAND RESERVE

Florida acres: 626,600

An auxiliary of the Church of Jesus Christ of Latter-day Saints, investor and operator Farmland Reserve earns returns to fund the church's mission and works.

Founded 75 years ago, the church's 295,000-acre Deseret Ranch in Orange, Osceola and Brevard is one of the nation's largest cow-calf operations. (Florida's role as a major cattle state is to produce calves that are shipped to feedlots in the central U.S.)

Farmland became Florida's largest private landowner in 2014 when it bought 382,000 acres of timberland in north Florida. Deseret Cattle & Timber, as Farmland calls its north Florida holdings, has 330,000 acres in Bay, Gulf, Calhoun, Liberty, Gadsden and Franklin counties. Farmland also has 2,600 acres in Suwannee County leased to local farmers. In addition to agriculture, Farmland leases land to utilities and solar power providers for seven solar power plants. Several more are in permitting and developing.

CEO Doug Rose says Farmland works to balance protecting natural resources while addressing Florida's growth. Farmland has hired Lake Nona developer Tavistock to create Sunbridge, a 27,447-acre project in Osceola and Orange counties, a step in developing Deseret. By 2080, the ranchland could have a half million residents.

Farmland last year petitioned the city of Orlando to annex 52,450 of Deseret's Orange County acres but was thwarted by a county-city agreement that stopped the annexation. Rose says Farmland will evaluate what to do next.

"With more than 70 years in Florida agriculture, we expect to be farming and ranching in Florida for many decades to come," Rose says. "Farmland Reserve and Deseret Ranch are not developers, but we intend to be involved in planning for how our land will be used as the rest of this century unfolds."

No. 2

FOUR RIVERS LAND & TIMBER CO.

Florida acres: 550,000

Hungarian native Thomas Peterffy came penniless to the United States in 1965 at age 21. He taught himself computer programming and pioneered electronic trading. He built his $42-billion fortune on a digital trading platform for sophisticated investors, Interactive Brokers. The Palm Beacher was Florida's richest man until Citadel founder Ken Griffin moved here in 2022 from Chicago.

Peterffy spent some of his wealth — at least $710 million — in 2015 to buy the timber holdings of business executive and investor Howard Leach's Foley Timber in Florida's Big Bend. The purchase made Peterffy the owner of the largest contiguous privately held property in Florida and one of the largest east of the Mississippi. It covers half of Taylor County and spreads into neighboring counties.

Travis McCoy, an executive under Leach's Foley who continues as a senior vice president in Perry with Four Rivers, says the Four Rivers plan is to "develop, manage and enhance the region's timber assets and, in doing so, support our local communities." He says that Four Rivers is "exploring opportunities" either alone or partnering with others "to increase and diversify wood consumption in our region."

Peterffy also owns 33,000 acres of Highlands County ranchland he purchased from the heirs of citrus baron Ben Hill Griffin Jr.

No. 3

RAYONIER

Florida acres: 397,000 leased and owned

Owner of a wealth of acres along Interstate 95 between Daytona Beach and Savannah, Rayonier, like most timber companies, historically sold land when development got close enough to reap more money from developers than timber. In 2016, it launched Wildlight in Nassau County, a lightly populated county on the Georgia border north of Jacksonville. The mixed-use development was to serve as a proof of concept that Rayonier could unlock value in the 3,000 acres around it and the 50,000 acres Rayonier owned within a 10-mile radius. "We believe the success of Wildlight will add substantial value to our neighboring timberlands," CEO David Nunes wrote to shareholders in his last annual report letter before retiring.

He said the company has engaged with local governments in northeast Florida and southeast Georgia about other Rayonier lands with development potential. He forecast that operating earnings from real estate development will average $40 million a year from 2026 to 2030, up from $28 million on average from 2021 to 2025. In New Zealand, the Pacific Northwest and Southern U.S., Rayonier owns 2.7 million acres. Most of the Southern timberland is in loblolly and slash pine. Rayonier didn't respond to questions by press time.

No. 4

MOSAIC

Florida acres: 368,000

The phosphate mining company's holdings in DeSoto, Hardee, Hillsborough, Manatee and Polk include land it owns outright and land on which it has mineral rights or mining agreements. Most of its present and future mining sites have been in company ownership for more than 50 years. Over time, as phosphate deposits are mined out, more of its land becomes available for uses other than phosphate operations. "Our long-term future land use strategy is to optimize the value of our land assets," it told investors in its last annual report. Mosaic received attention for reclaiming one former mining site to create the 7,000-acre Streamsong Resort hotel, golfing and conference center. It sold it in 2023 for $158 million for a gain of $57 million. Mosaic says the book value of its Florida phosphate mines and exploration properties is $1.9 billion. Mosaic didn't respond to questions. Its operations went offline in last year's hurricanes but were restored. Mosaic told investors it expected the fourth quarter to be short 200,000 to 250,000 tons of phosphate because of the storms.

No. 5

LYKES BROS.

Florida acres: 339,971

Founded in 1900 by doctor and rancher Howell Tyson Lykes and his seven sons, family-owned Lykes Bros. once encompassed Peoples Gas, Lykes hot dogs and meats, the state's fourth largest bank, Sunkist juice, insurance and a steamship line. After divesting those assets decades ago, Lykes Bros. nowadays relies on its ranching roots. Its 14,000-head herd is one of the largest cow-calf operations in America. Lykes Bros. also owns 274,268 acres in Texas.

In Florida, the majority of its land is in Glades County where it owns, according to the county Property Appraiser's office, 269,011 acres that the county values at $2.2 billion. It has another 69,733 acres in Highlands County.

The Lykes' portfolio includes row crops, forestry and hunting grounds plus water resource management. It has sold conservation easements on some of that land, which preserves it from development. In partnership with government, Lykes' land is home to three water projects totaling 26,000 acres that clean and store water in the Okeechobee watershed. Lykes employs 91 in Florida. "With our land and our people, we look forward to being a part of addressing Florida's future challenges and opportunities," says CEO Johnnie James.

No. 6

WEYERHAEUSER

Florida acres: 272,000

Seattle-based Weyerhaeuser became big in Florida via its 2016 merger with Plum Creek, once Florida's largest private landowner. Weyerhaeuser now owns 272,000 acres spread over 19 north-central Florida counties. One contiguous property, at 130,000 acres in Columbia, Union and Baker counties, includes a portion important to the "Florida Wildlife Corridor" connecting Ocala and Osceola national forests. A different portion of that property most likely will be developed, the company says. "The advantage of partnering with large landowners such as Weyerhaeuser is that we have a large enough footprint to properly plan for many different land uses — and also combining those uses to answer many public needs, from conservation to renewable energy development," says spokesman Deano Orr.

Orr notes that forest products are a cyclical industry currently in a downturn. In Florida, three pulp mills and two sawmills have closed or curtailed operations, part of an industry trend in the Southern U.S. "As a preferred supplier within our operating area, Weyerhaeuser will be well-positioned to take advantage of improved market conditions once they occur," Orr says.

Weyerhaeuser's North Florida Mega Industrial Park, a 2,622-acre site near Lake City, saw its first end-user, Michigan-based liquid fertilizer company AgroLiquid, break ground last year for a factory scheduled to open later this year.

Weyerhauser owns or controls 10.5 million acres of timberland in the United States and manages another 14.1 million under long-term leases in Canada.

No. 7

FPL

Florida acres: 251,466

The state's largest utility didn't make our 2011 list of the state's largest private property owners. Now it ranks seventh with 251,466 acres, thanks to its appetite for land for solar power plants, according to real estate firm SVN Saunders Ralston Dantzler.

FPL wouldn't tell Florida Trend how many acres it owns, but it did say it has 197,000 acres dedicated to current and future solar power plants. Its nuclear plant sites are 12,000 acres. That makes for 209,000 acres, but it, of course, has power plants and facilities across the 43 counties where it serves 12 million people.

In several counties across Florida, it's become one of the largest landowners. In Martin County, immediately north of Palm Beach County, for example, FPL owns 22,035 acres.

In 2023, it paid Dubai $212 million for the 40,000-acre El Maximo ranch in Osceola County. "We are very early in the process of determining potential uses at the El Maximo property," says FPL spokesman Marshall Hastings.

FPL says not every acre it owns for solar gets covered by panels. It also says it will build solar only so long as it's the lowest cost way to deliver power. While awaiting development into solar power plants, FPL licenses land to local ranchers and growers, which lowers costs.

Solar Size

The most land-hungry form of electricity generation re-shapes the Florida landscape, turning pasture, defunct orange groves and timber stands into legions of solar panels. Florida Trend in 2023 estimated 40,000 to 48,000 acres of Florida already were occupied by utility-scale solar power plants. It's only growing.

Consider the state's solar leader. In the next three years alone, Juno Beach-based FPL plans 46 new solar sites totaling 42,872 acres, or 66 square miles. Its 10-year site plan filed with the state Public Service Commission envisions adding 21,009 megawatts of solar power by 2033, up from its 4,803 megawatts at year-end 2023. That equals 282 new solar power plants. As of April, it had 88 solar facilities, according to a PSC filing.

No. 8

U.S. SUGAR

Florida acres: 233,500

Longtime U.S. Sugar CEO Robert Buker Jr. and lead lobbyist Robert Coker both retired a year ago. But the guiding plan remains the same for the 1,200-employee company based in Clewiston in Hendry County: Use its land around Lake Okeechobee to farm sugar and other commodities.

U.S. Sugar produces 15% of the nation's sugar on the 175,000 acres it plants in sugarcane. It owns a 300-mile short-line railroad serving the farming region. It plants 14,263 acres in sweet corn. The region is the largest source of winter and spring sweet corn on the eastern seaboard.

Founded in 1931 by General Motors co-owner Charles Mott, the company has been majority-owned by its employees since the 1980s. (Mott's foundation still has a stake, as does the Mott Children's Health Center in Mott's hometown of Flint, Mich.) The company has bought land in recent years north of Lake Okeechobee in Martin, Hendry, Glades and Palm Beach counties from farming companies Duda, Knight Management and others. Spokesman Ryan Duffy says the company is open to acquiring more land on a "case-by-case" basis.

Buker, upon retiring, said that over his career, U.S. Sugar "confronted legal, political, and constitutional challenges from activists, and emerged from them not only victorious but also with our integrity intact. Time has proven that our decisions have been to the benefit of our shareholders, our employees and our communities."

No. 9

ST. JOE CO.

Florida acres: 168,000

Historically Florida's largest private landowner, St. Joe pivoted in 2015, selling 382,000 acres — to No. 1 on our list, Farmland Reserve — to focus on developing the largest planned community in Florida. Today, 87% of St. Joe land is in Bay, Walton and Gulf counties in Northwest Florida, and 90% of it is within 15 miles of the Gulf of Mexico. St. Joe's plan keeps 53,000 acres in conservation while developing the remaining 110,500 acres over 50 years.

Its development strategy included donating the land for the Northwest Florida Beaches International Airport and for schools, parks and sports parks.

A second pivot came nearly a decade ago. The former timberland and paper company would continue selling land to home builders. But it would also create recurring revenue streams in the form of company-owned hotels, offices and shopping centers. Such development makes residential land more attractive to permanent residents who in turn patronize stores and offices, creating a virtuous circle. Leasing revenue in 2023 hit $50.8 million, up from $9.8 million in 2016.

"We live in this community and we're here every day," says St. Joe spokesman Mike Kerrigan. "Our kids go to the schools in these communities where we have our projects. It puts you in a different mindset as a developer. When we go to church or the grocery store, people know we're here."

No. 10

FLORIDA CRYSTALS

Florida acres: 161,000

The Fanjul family began milling sugar in Cuba 175 years ago. After Fidel Castro set up his dictatorship, the Fanjuls started over in Florida. Their Florida Crystals has an agricultural waste-to- electricity renewable energy plant in Palm Beach County to power its operations. It also grows rice. But it's best known for growing sugar and vegetables in the Everglades Agricultural Area. It owns the largest Regenerative Organic Certified farm in the country. It's also the only such certified sugarcane grower in the United States and built one of the 10 largest compost facilities in America. (Palm Beach, as the company notes, is the nation's winter vegetable capital and is the largest agricultural county east of the Mississippi.) Florida Crystals employs 2,000, all told, and farms 196,700 acres — 161,000 of which it owns — almost entirely in Palm Beach County. Because it puts owl nesting boxes on its farmlands, it has one of the highest concentrations of barn owls in America. Owls control rodents without using rodenticides. The Fanjuls also own 240,000 acres in the Dominican Republic and own Domino Sugar and other brands. The family in Florida has two sugar mills, a sugar refinery, a rice mill powered by a solar array, a packaging plant and a Tesla megapack battery storage system.

The Long Goodbye?

In 1970, Florida had 941,471 acres planted in citrus. That was about one in every 35 acres in the state. Today, the number of acres has fallen by two-thirds. Greening disease, which appeared in Florida in 2005, decimated groves.

U.S. Sugar, Florida's seventh largest private landowner, in the mid-1980s had 29,000 acres of orange groves. It now has 1,000 acres. It closed its citrus plant in 2019 and has been converting groves to sugarcane and vegetables.

Lykes Bros., Florida's fifth largest private landowner, has also greatly reduced acreage in active citrus production. Lykes itself has less than 1000 acres in active production and leases an additional 16,767 acres to others for citrus operations. "Even with the many challenges, the rich history of the citrus industry along with the ongoing commitment to research and innovation gives us some optimism, but time is running out on the industry," says Lykes President and CEO Johnnie James.

"*We're really seeing the citrus industry as we know it disintegrate in front of our eyes. That opens up a lot of land, and what do you do with it? Do you convert it to another ag use? Do you convert it to solar? Or do you convert it for houses? Those are the big questions.*"

— **Dean Saunders**, founder and managing director of ***SVN Saunders Ralston Dantzler Real Estate***

Tree Debris

Little attention gets paid but large losses are incurred when hurricanes batter timberland.

Hurricane Helene in September made landfall in Taylor County, half of which is timberland owned by Four Rivers Land & Timber Co., the state's second largest private landowner. Damage from Helene "is significant both in acreage and economic impact," Four Rivers Senior Vice President Travis McCoy says.

Category 5 Hurricane Michael in 2018 did such damage to Forest Investment Associates' (FIA) Bear Creek holdings that the firm had to replant more than 40,000 acres with 20 million trees — "bringing this land back into sustainable working forest and demonstrating our commitment to stewardship of our land," says Chad Lincoln, FIA's southern region operations manager. Atlanta-based FIA manages 155,000 acres in Florida for clients. It’s one of Florida’s largest private landowners, though not in the top 10. “The damage on Bear Creek from Michael was unlike anything ever experienced on our properties,” one of its executives wrote in an industry publication. It took a month to reopen the primary forestry roads. Older stands of trees had as much as 150 to 200 tons of debris per acre. Novel solutions to clearing debris included a combination of heavy equipment and hundreds of feet of ship-anchor chain.

Timber is a cyclical industry. In 2021, the state had 16.8 million acres of timberland. That was 634,407 more acres than in 2004 but down 621,245 acres from 2011, a recent peak for timber, the Florida Forest Service reports.

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Florida Trend Media Company
801 Third Street South
St Petersburg, FL 33701
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