BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	))))	**DOCKET NO. 20250011-EI**

Direct Testimony and Exhibits of

Matthew P. Smith

On behalf of

Federal Executive Agencies

June 9, 2025

BRUBAKER & ASSOCIATES, INC.

Project 11813

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	)	**DOCKET NO. 20250011-EI**

STATE OF MISSOURI	)	
	)	**SS**
COUNTY OF ST. LOUIS	)	

Affidavit of Matthew P. Smith

Matthew P. Smith, being first duly sworn, on his oath states:

1. My name is Matthew P. Smith. I am a consultant with Brubaker & Associates, Inc., having its principal place of business at 16690 Swingley Ridge Road, Suite 140, Chesterfield, Missouri 63017. We have been retained by the Federal Executive Agencies in this proceeding on their behalf.

2. Attached hereto and made a part hereof for all purposes is my direct testimony and exhibits which were prepared in written form for introduction into evidence in the Florida Public Service Commission Docket No. 20250011-EI.

3. I hereby swear and affirm that the testimony and exhibits are true and correct and that it shows the matters and things that it purports to show.

Matthew Smith

Matthew P. Smith

Subscribed and sworn to before me this 9th day of June, 2025.

TAMMY S. KLOSSNER
Notary Public - Notary Seal
STATE OF MISSOURI
St. Charles County
My Commission Expires: Mar. 18, 2027
Commission # 15024862

Tammy S Klossner

Notary Public

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	))))	**DOCKET NO. 20250011-EI**

Table of Contents to the Direct Testimony of Matthew P. Smith

I. INTRODUCTION 1

II. SUMMARY OF TESTIMONY 2

III. COST OF SERVICE PROCESS OVERVIEW 4

IV. FPL'S CLASS COST OF SERVICE 7

V. REVISED CLASS COST OF SERVICE 13

Qualifications of Matthew P. Smith .... Appendix A

Exhibit MPS-1: 2026 Revised CCOSS

Exhibit MPS-2: 2027 Revised CCOSS

Exhibit MPS-3: Renewable Resources Nameplate and Accredited Capacity

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.	))))	**DOCKET NO. 20250011-EI**

Direct Testimony of Matthew P. Smith

I. INTRODUCTION

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Matthew P. Smith. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A I am appearing in this proceeding on behalf of the Federal Executive Agencies ("FEA").

Q WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A My testimony will address FPL's proposed Class Cost of Service Study ("CCOSS"). First, I respond to FPL's proposal to increase the energy classification of production capacity cost to 25% from 1/13th. FPL's rationale for this change does not align with how it incurs production demand costs to reliably service customers' demands in all hours of the year at the lowest energy cost available. Second, I will also describe my concerns with FPL's proposed demand allocation factors based on a 12-Coincident Peak ("12CP") allocation factor. I explain why a 4-Coincidence Peak ("4CP") demand allocation factor better aligns with FPL's system peak demand periods making it a more accurate demand allocation factor which assigns production demand to rate classes in line with how FPL incurs production and transmission capacity costs needed to reliably service each rate classes' demands in all hours of the year.

Finally, I will also provide my recommended revised CCOSS using my proposed adjustments to the energy demand classification of production capacity costs with my proposed 4CP demand allocation factors for production and transmission capacity costs.

My silence with respect to any position taken by FPL should not be construed as agreement with that position.

II. SUMMARY OF TESTIMONY

Q HOW IS YOUR TESTIMONY ORGANIZED?

A My testimony is organized as follows:

1. I will present an overview of Cost of Service ("COS") principles and concepts.
2. I outline the issues I take with FPL's CCOSS.
    a. I address FPL's use of a 12-Coincidence Peak allocator for production and transmission purposes.
    b. I then oppose FPL's recommendation to adjust the classification of production capacity cost from 1/13 energy to 25% energy. I

recommend the Commission continue to classify FPL's production capacity cost as 1/13th energy and demand.

3. I present the results of my revised CCOSS study and compare its result to those in FPL's CCOSS.
4. My testimony concludes with a discussion of the appropriateness of my revisions to FPL's CCOSS, including the use of 4CP, 1/13th energy, production plant allocator, and a 4CP transmission allocator.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations are as follows:

1. Class cost of service is the foundation for allocating revenue to classes within the ratemaking procedure.
2. A 4CP production and transmission demand allocator is a more accurate measure of the capacity cost FPL must incur to provide reliable firm service to its rate classes. I recommend the Commission approve a 4CP demand allocation factor in this case for production and transmission capacity cost classified as demand.
3. I oppose FPL's proposal to increase the energy classification of production capacity cost from 1/13th energy, which has been used in past rate cases, to 25% in this case. FPL's proposal to increase the energy classification weight in allocating production fixed capacity cost is not cost justified and does not align with how FPL incurs production capacity cost to reliably service customer demands at the lowest cost energy available. It should therefore be denied.
4. The results of the CCOSS with a 4CP, 1/13th energy classification, better allocates capacity costs based on cost-causation principles and is fair and reasonable to all rate classes.

5. Following cost-causation principles allows the Utility to send actual and efficient cost-based price signals to all customers to encourage customers to make efficient conservation consumption decisions. Enhancing the efficiency of customers' demands will produce benefits to both customers and the Utility by enhancing the economic utilization of the utility rate base assets.
6. Class revenue should be allocated using the FEA's proposed CCOSS revenue spread, as shown on Exhibit MPS-1. This CCOSS utilizes a 4CP, $1/13^{th}$ energy production plant allocator.

III. COST OF SERVICE PROCESS OVERVIEW

Q WHAT IS THE PURPOSE OF A CCOSS?

A The CCOSS gathers the costs incurred to serve all customers on the system and identifies, or allocates, those costs to the customer classes which caused the costs to be incurred. Likewise, revenues collected are allocated by class so that a rate of return can be calculated for each class. The rate of return for each class can then be compared to the system authorized rate of return.

A customer class with a rate of return equal to the system rate of return is considered to be at "parity," or covering the costs incurred to serve its load. A class with a rate of return which exactly equals the system rate of return would be calculated to have a parity index rating of 1.0. A class with a below parity, or below average, rate of return could be considered to have insufficient revenue to cover all costs to serve that class and would have a parity index rating below 1.0. However, classes above a parity index rating of 1.0 are considered to be covering the cost associated with their own load and the costs incurred by other, below parity classes.

Q WHY IS IT IMPORTANT TO HAVE AN ACCURATE CCOSS?

A It is a widely held principle that costs should be allocated to customer classes based on cost causation. While some costs, such as meters, can readily be assigned directly to individual customer classes, a mechanism is required to properly allocate other costs which cannot be as readily assigned. The CCOSS is that mechanism. The results of the CCOSS will be used to assign costs and produce revenues from each customer class. As such, it is fundamental to the ratemaking process to have an accurate representation of how costs are incurred and from which class they were incurred.

Q DO YOU SUPPORT THAT PREMISE?

A Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation, and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions, i.e., how much energy to consume, at what rate, and when, they tend to take actions which not only minimize their own costs but those of the utility as well.

Although factors such as simplicity, gradualism, economic development, and ease of administration may also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q WHAT ARE THE MAJOR STEPS IN A CCOSS?

A The first step in a CCOSS is known as <u>functionalization</u>. This simply refers to the process by which the utility's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission, and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as classification. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related, and customer-related costs in order to facilitate the allocation of costs applying the cost-causation principles.

Demand or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines, and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatt-hours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. Thus, the fuel expense is almost directly proportional to the amount of kilowatt-hours supplied by the utility system to meet its customers' energy requirements.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services, and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation, and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the allocation of each category of the functionalized and classified costs to the various customer classes using the cost-causation principles. Demand-related costs are allocated on the basis that gives recognition to each class's responsibility for the Company's need to build plants to serve demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

IV. FPL'S CLASS COST OF SERVICE

Q PLEASE DESCRIBE THE COMPANY'S CCOSS.

A Ms. DuBose describes the Company's CCOSS in her testimony. She also presents an alternative CCOSS utilizing a 12CP, 1/13th energy allocator for production plant but states this is for informational purposes only and is not the basis of FPL's proposal in this proceeding.[1]

Ms. DuBose states her CCOSS starts by allocating costs between retail and wholesale jurisdictions. Costs are first functionalized, then classified, and finally separated between retail and wholesale jurisdictions. Then, the retail costs are functionalized, classified, and allocated to retail rate classes.[2]

Q DO YOU BELIEVE FPL'S PRODUCTION PLANT AND TRANSMISSION ALLOCATORS FOLLOW COST-CAUSATION PRINCIPLES?

A No. Use of a 12CP allocator does not accurately present the load contribution of the retail classes that drive FPL's need to invest in production and transmission

[1] Direct Testimony of Tara DuBose, pages 24 & 25.
[2] Direct Testimony of Tara DuBose, pages 13 thru 20.

capacity. The class contribution to the peak loads drives FPL's cost of providing firm service, and this capacity cost should be allocated across rate classes in proportion to how this cost is incurred.

Q WHY IS FPL'S PROPOSED USE OF A 12CP ALLOCATOR FOR TRANSMISSION AND PRODUCTION PLANT CAPACITY CLASSIFIED COSTS NOT REFLECTIVE OF FPL's COST CAUSATION?

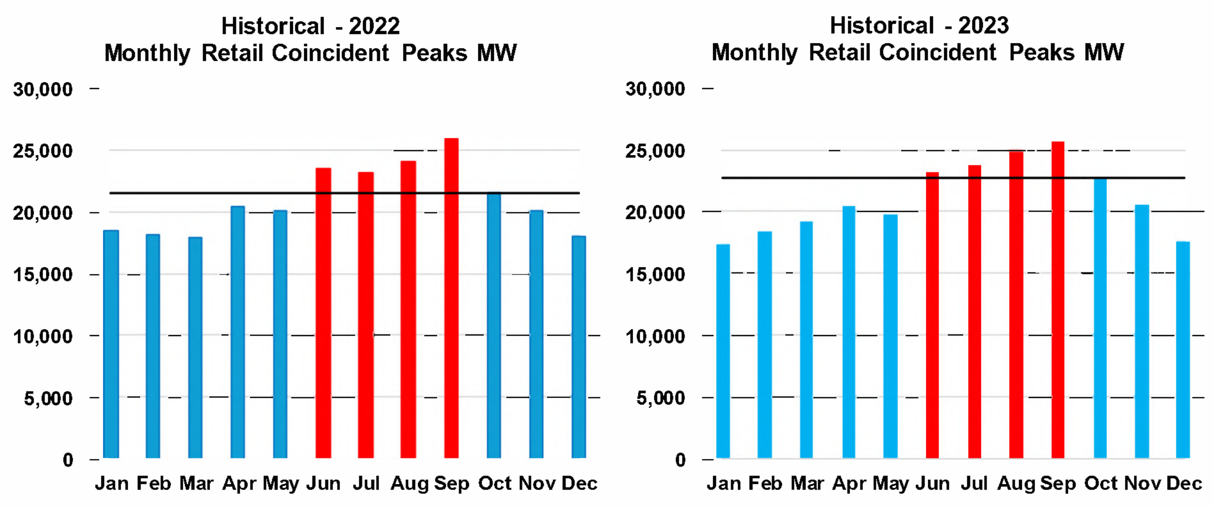
A FPL must invest in production and transmission capacity that is capable of serving its customers' demands in every hour of the year. The peak hours demands are the primary investment factor that drive FPL's decisions to invest in adequate amounts of production and transmission capacity resources to enable it to meet its customers firm service demands. The demand allocator then must reflect both peak demand of the FPL system and the amount of accredited capacity needed to reliably service the peak demand.

Q HOW DOES FPL'S MONTHLY PEAK DEMAND IMPACT ITS NEED FOR PRODUCTION AND TRANSMISSION CAPACITY RESOURCES?

A FPL must invest in capacity resources that are capable of servicing demand in all hours of the year, including the peak period hours. This requires FPL to make investment decisions that will fully utilize all production and transmission capacity resources during peak periods but will allow it to reduce the capacity utilization output of its production and transmission resources during non-peak periods. That is, the capacity factor of FPL's capacity resources will be lower during off-peak periods but its capacity will be used on all hours. Importantly, the amount of capacity that is needed to provide reliable firm service is based on peak period demands.

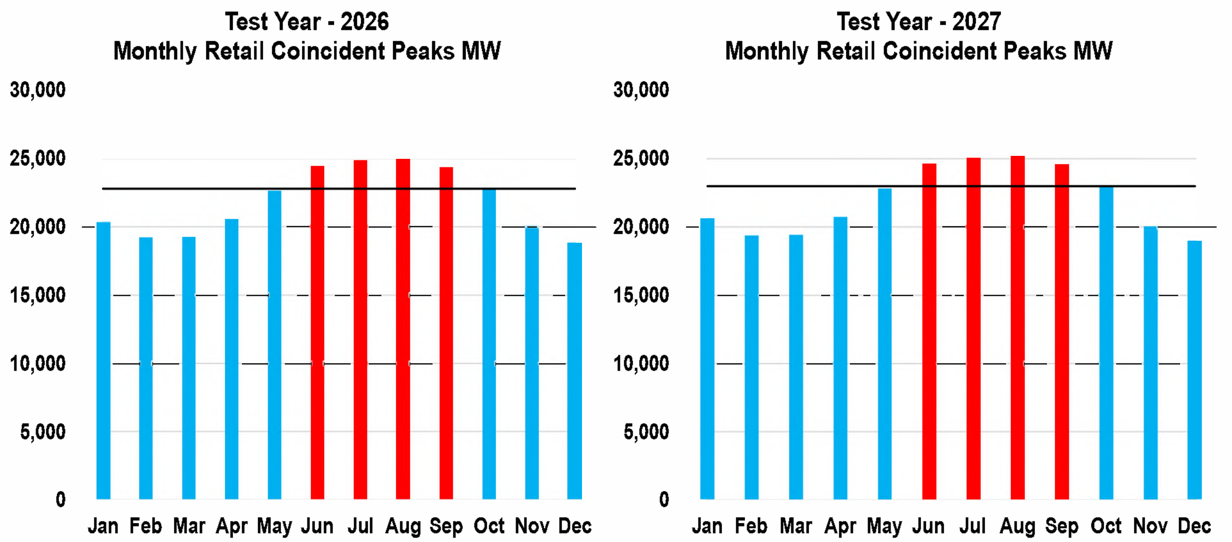
An examination of FLP's historic and test year retail monthly peak demands is illustrated in Figure 1 below. As shown in Figure 1, FPL must invest in capacity to meet its peak period demands, which occur 4 months of the year. In the other 8 months of the year, FPL demands are well below the 4 monthly peak demand months. Figure 1 illustrates that FPL must invest in capacity resources that are adequate to serve its peak period demands, and those demands are represented by a 4CP demand. During the historic years of 2022 and 2023, the retail load begins to rise in the month of June, remains elevated, and begins to sharply decline in October. FPL's forecast for test years 2026 and 2027 expresses a similar pattern, with the peak in August, before a return to pre-summer month levels in October. FPL must invest in resource capacity amounts that can reliably serve demands in these four months. That capacity will not be operated at high capacity output in the remaining 8 months of the year.

FIGURE 1



Sources: MFR E-11, Attachments 1 & 2.

FIGURE 2



Sources: MFR E-11, Attachments 1 & 2.

If FPL made investment decisions based on a 12CP period, then it would not have adequate resource capacity amounts to reliable serve its demands in every hour of the year. For this reason, a 12CP capacity allocation factor does not accurately describe the amount of capacity FPL needs to reliable serve its customer demands in every hour of the year.

Q **HOW DOES FPL INVEST IN PRODUCTION RESOURCES TO SERVE ITS PEAK DEMANDS IN EVERY HOUR OF THE YEAR?**

A. In his testimony, FPL witness Mr. Whitley describes three reliability criteria which FPL relies upon to design its resource portfolio: 1) Minimum total planning reserve margin (“PRM”) of 20% for both summer and winter peak hours. 2) Loss of load probability (“LOLP”). 3) Minimum generation-only reserve margin (“GRM”) of 10%.[3] The PRM requirement ensures FPL has a reserve margin, for capacity, available above 20% of the summer, or winter, peak.[4] The LOLP method looks at the peak

[3] Direct Testimony of Andrew Whitley, pages 10 – 11.
[4] *Id.*

hourly demand for each day of the year and assesses the probability of generation shortfalls in the system firm demand. Lastly, the GRM requires available firm capacity be 10 percent greater than the sum of customer seasonal demands.[5]

Each of the above criteria utilized by FPL requires investment in production resources to meet the Utility's firm capacity needs. As a result, to reliability serve customers, FPL acquires generation resources based on each resource type's accredited capacity ratings. The accredited capacity rating for all resources are typically less than the resource nameplate rating. The accredited capacity rating for FPL's proposed solar and battery storage units reflects the expected capacity amount that the resource will be available to deliver to serve FPL's load demands, as seen on Exhibit MPS-3.

Q WHY IS FPL'S PROPOSED CHANGE IN CLASSIFICATION OF PRODUCTION CAPACITY FROM 1/13TH ENERGY TO A 25% ALLOCATION NOT REASONABLE?

A In her testimony, Ms. Dubose asserts the move from a 1/13 energy allocation, which is approximately 8%, to 25%, "offers a more suitable allocation of production plants."[6] Ms. Dubose's reasoning for this claim is the addition of significant solar and battery storage with zero fuel costs, which is a benefit to all customers. However, increasing solar installations on the system have caused the net system peak for generation to shift to later in the evening, when solar will offer a minimal contribution to the system's coincident peak.[7]

---

[5] *Id.*
[6] Direct Testimony of Tara Dubose, page 21.
[7] Direct Testimony of Tara Dubose, pages 21 & 22.

While it's correct to say solar panels will not be generating capacity during a peak occurring later in the evening, it is unreasonable to assert the solar panels will not be contributing to the system's coincident peak via the additional battery storage units which Mr. Whitley has asserted will be charged during the day as a direct product of FPL's large amounts of solar on the system.[8] As noted above, production resources, which includes solar and battery storage units, are selected based on firm capacity ratings, not energy, in order to meet the system peak demands. The allocation of those demand costs should align with the incurrence of those costs.

Q IS MS. DUBOSE'S REASONING SOUND?

A. No. While I agree a lower fuel cost is a benefit, modifying the production capacity classification does not reflect how FPL invests in adequate amounts of capacity to provide reliable firm service, nor how it operates its capacity to minimize fuel costs.

Production costs reflect the capital investment required to meet the Company's peak system capacity requirements. Capital investments are a fixed cost based on the required capacity needed to provide firm service. The energy cost is the cost to operate the capacity resources to economically generate energy. Ms. DuBose recognizes this distinction in her direct testimony.[9] Shifting capacity cost recovery to energy cost directly contravenes cost-causation and sends erroneous price signals to customers. While an increase to the energy allocation will collect more revenue from high energy users on the Utility's system, it will shift costs away from customers causing the system peak in the later portion of the day by reducing the cost allocated to incur capacity during the peak period. This is a direct reversal of the purpose of price signals, which the principles of cost-

[8] Direct Testimony of Andrew Whitley, pages 25 – 26.
[9] Direct Testimony of Tara Dubose, pages 21 & 22.

causation are meant to enforce, through which customers, large and small, are able to make informed and responsible decisions about their energy use. An informed, responsible customer base provides a direct benefit to the Utility by allowing it to collect revenues in-line with actual cost-causation.

V. REVISED CLASS COST OF SERVICE

Q DID YOU REVISE FPL'S CCOSS TO MORE ACCURATELY ALLOCATE PRODUCTION AND TRANSMISSION DEMAND COSTS?

A Yes. I adjusted FPL's CCOSS with revised production and transmission demand allocators. I recommend transmission allocation move from FPL's 12CP allocator to a 4CP allocator, while production demand is revised from FPL's 12CP, 25% energy allocator to a 4CP, 1/13 energy allocator.

These production and transmission allocators more accurately align with FPL's incurrence of capacity needs and system peak demands.

Q HOW DOES THE FEA'S REVISED CCOSS REVENUE INCREASE COMPARE TO FPL'S CCOSS RESULTS?

A FPL created 2 CCOSS for test years 2026 and 2027. In order to make direct comparisons, I duplicate this process, creating revised CCOSS for 2026 and 2027 using a 4CP, 1/13 energy allocator for production plant and a 4CP allocator for transmission presented in Exhibits MPS-1 and MPS-2, respectively. A comparison of the resulting CCOSS revenue requirements can be seen below in Tables 1 and 2 for years 2026, and 2027, respectively.

TABLE 1
Comparison of Proposed Target Equalized Revenue Requirements
By Rate Class 12CP Production/Transmission Allocator VS 4CP
For Test Year 2026
($M)

	Flordia Power & Light Company CCOSS				FEA Revised CCOSS			
Rate Class (1)	Achieved Revenues (2)	Revenue Deficiency/ (Excess) (3)	Percent Difference (4)	Increase Index (5)	Achieved Revenues (6)	Revenue Deficiency/ (Excess) (7)	Percent Difference (8)	Increase Index (9)
CILC-1D	$110.5	$41.7	37.7%	2.4	$110.5	$28.9	26.2%	1.7
CILC-1G	5.1	1.4	27.3%	1.7	5.1	1.0	19.3%	1.2
CILC-1T	47.6	17.5	36.8%	2.4	47.6	7.6	16.0%	1.0
GS(T)-1	746.4	(0.1)	0.0%	0.0	746.6	29.4	3.9%	0.3
GSCU-1	2.4	(0.1)	-5.2%	-0.3	2.4	(0.4)	-15.4%	-1.0
GSD(T)-1	1,762.1	482.1	27.4%	1.8	1,762.0	455.2	25.8%	1.7
GSLD(T)-1	557.9	198.6	35.6%	2.3	557.8	165.6	29.7%	1.9
GSLD(T)-2	180.6	79.0	43.8%	2.8	180.6	64.3	35.6%	2.3
GSLD(T)-3	33.0	9.7	29.4%	1.9	32.9	6.1	18.5%	1.2
MET	4.4	0.5	11.4%	0.7	4.4	0.2	3.8%	0.2
OS-2	2.1	1.2	54.7%	3.5	2.1	1.1	51.8%	3.3
RS(T)-1	6,229.8	700.1	11.2%	0.7	6,230.0	776.8	12.5%	0.8
SL/OL-1	191.1	16.3	8.5%	0.5	191.1	12.8	6.7%	0.4
SL-1M	1.6	0.2	12.8%	0.8	1.6	(0.0)	-1.0%	-0.1
SL-2	1.9	0.1	7.6%	0.5	1.9	(0.1)	-4.9%	-0.3
SL-2M	0.6	(0.1)	-13.5%	-0.9	0.6	(0.1)	-21.0%	-1.3
SST-DST	0.2	(0.1)	-61.9%	-4.0	0.2	(0.1)	-62.2%	-4.0
SST-TST	$7.3	($3.3)	-44.6%	-2.9	$7.3	($3.3)	-45.2%	-2.9
System Total	$9,884.8	$1,544.8	15.6%	1.0	$9,884.8	$1,544.8	15.6%	1.0

Sources:
(2) & (3) Exhibit TD-3 Target RR at Proposed Rate.
(4) Column (3)/ Column (2).
(5) & (9) Percent Difference, for each class/System Total Increase.
(6) Exhibit MPS-1, tab Revised 2026 COS Present Rates.
(7) Exhibit MPS-1, tab Revised 2026 COS Proposed Rates.
(8) Column (7)/Column (6).

TABLE 2
Comparison of Proposed Target Equalized Revenue Requirements
By Rate Class 12CP Production/Transmission Allocator VS 4CP
For Test Year 2027
($M)

	Flordia Power & Light Company CCOSS				FEA Revised CCOSS			
Rate Class (1)	Achieved Revenues (2)	Revenue Deficiency/ (Excess) (3)	Percent Difference (4)	Increase Index (5)	Achieved Revenues (6)	Revenue Deficiency/ (Excess) (7)	Percent Difference (8)	Increase Index (9)
CILC-1D	$110.8	$53.0	47.8%	1.9	$110.8	$39.3	35.5%	1.4
CILC-1G	5.2	1.9	36.8%	1.5	5.2	1.5	28.3%	1.1
CILC-1T	48.0	23.4	48.8%	2.0	48.0	12.8	26.6%	1.1
GS(T)-1	754.1	64.0	8.5%	0.3	754.3	95.7	12.7%	0.5
GSCU-1	2.4	0.1	3.7%	0.1	2.4	(0.2)	-7.2%	-0.3
GSD(T)-1	1,783.2	653.8	36.7%	1.5	1,783.2	625.0	35.1%	1.4
GSLD(T)-1	558.4	253.4	45.4%	1.8	558.3	218.2	39.1%	1.6
GSLD(T)-2	181.7	98.6	54.3%	2.2	181.6	83.0	45.7%	1.8
GSLD(T)-3	33.2	13.6	41.0%	1.7	33.2	9.7	29.3%	1.2
MET	4.5	0.9	20.3%	0.8	4.5	0.5	12.2%	0.5
OS-2	2.1	1.2	57.8%	2.3	2.1	1.2	54.8%	2.2
RS(T)-1	6,302.2	1,272.7	20.2%	0.8	6,302.4	1,353.8	21.5%	0.9
SL/OL-1	195.6	43.3	22.1%	0.9	195.6	40.0	20.4%	0.8
SL-1M	1.7	0.3	18.8%	0.8	1.7	0.1	4.0%	0.2
SL-2	1.9	0.3	18.3%	0.7	1.9	0.1	5.0%	0.2
SL-2M	0.6	(0.0)	-5.8%	-0.2	0.6	(0.1)	-13.9%	-0.6
SST-DST	0.2	(0.1)	-58.4%	-2.4	0.2	(0.1)	-58.8%	-2.4
SST-TST	$7.3	($2.7)	-37.1%	-1.5	$7.3	($2.8)	-37.9%	-1.5
System Total	$9,993.2	$2,477.7	24.8%	1.0	$9,993.2	$2,477.7	24.8%	1.0

Sources:
(2) & (3) Exhibit TD-3 Target RR at Proposed Rate.
(4) Column (3)/ Column (2).
(5) & (9) Percent Difference, for each class/System Total Increase.
(6) Exhibit MPS-2, tab Revised 2027 COS Present Rates.
(7) Exhibit MPS-2, tab Revised 2027 COS Proposed Rates.
(8) Column (7)/Column (6).

Columns 5 and 9 of Tables 1 and 2, respectively, display an Increase Index. This index is calculated by taking the required revenue deficiency/(excess) percent difference, displayed in columns 4 and 8 of each table, divided by the respective system total required revenue deficiency/(excess) percent difference. This creates an index, similar to the parity index, to compare each classes required revenue change to the system average change. A score of 1.0 reflects a class revenue change equal to the system average.

In Table 1, the 2026 CCOSS Comparison, the majority of rate classes for the FEA revised CCOSS have an Increase Index closer to 1.0 when compared to the respective increase from FPL's CCOSS. Under FPL's CCOSS, rate CILC-1D would receive an increase of 37.7%, or an Increase Index of 2.4. The FEA revised CCOSS increase for CILC-1D is a more moderate increase of 26.2%, or an Increase Index of 1.7. GSD(T)-1 is allocated a 27.4% increase, or an Increase Index of 1.8 under FPL's CCOSS, while receiving a 25.8% increase with an Increase Index of 1.7 under the FEA's revised COSS. RS(T)-1, under FPL's CCOSS, receives an 11.2% increase, an Increase Index of 0.7, compared to a 12.5% increase at an Increase Index of 0.8 under the FEA Revised CCOSS.

In table 2, the 2027 CCOSS Comparison, a similar trend to that which is observed in table 1, and outlined above, is present. The Increase Index for rate classes CILC-1D, GSD(T)-1, and RS(t)-1 all move closer to 1.0, as well as the majority of other rate classes.

Q WHY IS HAVING AN INCREASE INDEX CLOSER TO 1.0 A POSITIVE FOR RATE CLASSES?

A An Increase Index of 1.0 can be a positive indicator of a CCOSS model's stability. The system average increase is a benchmark for classes as it represents the Utility's total revenue increase requirement. Each component of the CCOSS should be individually examined, and cost causation should be represented in the CCOSS. However, wider swings in rate class increases/(decreases) to revenue responsibility can be a result of inappropriate changes to cost allocation methods. In this rate case proceeding, FPL has presented a modification to the production plant allocator, increasing the energy allocator proportion from 1/13, or approximately 8%, to 25%. The resulting CCOSS revenue requirements and the further those increases depart from the system Increase Index of 1.0, the more apparent the shift of revenue responsibility for rate classes becomes.

Gradualism, another key consideration in a properly formed CCOSS, is also served when classes' Increase Index is closer to 1.0. As I discussed earlier, the aim of a CCOSS is to form a foundation for rates that are based on consistently applied cost-causation principles which are not only fair and reasonable, but further the cause of stability, conservation, and efficiency. An accurate and fair CCOSS is the goal in the ratemaking process. The FEA's proposed CCOSS, when compared to FPL's, demonstrates a more gradual alignment of revenues for rate classes.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A – Qualifications of Matthew P. Smith

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Matthew P. Smith. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q PLEASE STATE YOUR OCCUPATION.

A I am a Consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A In 2017, I received a Bachelor of Science Degree in Economics from Southern Illinois University.

In May of 2018, I accepted an Analyst position with Brubaker & Associates, Inc. ("BAI"). I was promoted to Senior Analyst in 2021, and in 2023 I was promoted to Consultant. During my employment at BAI I have performed detailed analysis on a variety of subjects within the scope of electric, natural gas, and water regulatory proceedings. This analysis includes but is not limited to the following: Cost of Service Studies ("COSS"), Return on Equity ("ROE"), Rate Design, and Resource Adequacy issues. I have also been engaged in the evaluation of Request for Proposals ("RFP") responses, the creation of regional electric market price forecast models, and load forecast models for industrial energy users in the electric and natural gas fields.

BAI was formed in April 1995. BAI and its predecessor firm have participated in more than 700 regulatory proceedings in 40 states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, state regulatory agencies, and some utilities. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky and Phoenix, Arizona.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of service, and other issues, before the California state regulatory commission.

530536

FLORIDA POWER AND LIGHT COMPANY
2026 REVISED CLASS COST OF SERVICE STUDY
(4CP PRODUCTION, 1/13 ENERGY ALLOCATOR)

MFR E-1 - COST OF SERVICE STUDY
2026 EQUALIZED AT PROPOSED ROR
($000 WHERE APPLICABLE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Methodologies: 12CP and 25%	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
1	**RATE BASE -**																			
2	Electric Plant In Service	86,274,360	1,020,661	45,836	390,760	5,988,317	15,855	16,497,481	5,336,757	1,778,600	278,065	35,804	25,038	53,132,955	1,661,618	12,037	13,807	3,434	828	36,508
3	Accum Depreciation & Amortization	(17,683,082)	(202,333)	(9,155)	(75,441)	(1,256,887)	(3,723)	(3,280,272)	(1,057,593)	(351,435)	(53,434)	(7,397)	(4,807)	(11,150,686)	(216,605)	(2,651)	(2,587)	(863)	(205)	(7,008)
4	Net Plant in Service	68,591,278	818,327	36,681	315,319	4,731,429	12,132	13,217,208	4,279,164	1,427,164	224,631	28,407	20,231	41,982,269	1,445,013	9,387	11,220	2,571	624	29,501
5	Plant Held For Future Use	1,475,168	19,631	854	9,745	103,175	236	303,493	99,427	34,104	6,920	643	124	894,385	1,190	110	227	39	3	861
6	Construction Work in Progress	2,012,666	24,086	1,074	9,493	139,263	378	383,942	125,166	41,881	6,703	808	533	1,241,467	36,307	286	332	85	15	847
7	Net Nuclear Fuel	745,109	14,205	574	8,163	49,138	184	170,272	62,731	22,819	5,240	385	82	407,592	2,696	217	180	37	0	593
8	Total Utility Plant	72,824,221	876,251	39,182	342,720	5,023,005	12,930	14,074,915	4,566,487	1,525,968	243,495	30,243	20,970	44,525,713	1,485,207	10,000	11,958	2,733	642	31,802
9	Working Capital - Assets	5,812,779	71,258	3,088	31,667	415,221	1,526	1,054,439	351,546	120,657	21,497	2,341	1,187	3,662,004	71,181	1,043	1,068	398	42	2,616
10	Working Capital - Liabilities	(3,507,123)	(43,216)	(1,865)	(19,389)	(250,195)	(918)	(634,658)	(212,222)	(73,041)	(13,116)	(1,396)	(692)	(2,211,621)	(41,656)	(639)	(649)	(244)	(23)	(1,582)
11	Working Capital - Net	2,305,655	28,042	1,223	12,279	165,026	608	419,780	139,324	47,616	8,381	945	495	1,450,382	29,524	404	419	154	19	1,034
12	**Total Rate Base**	75,129,876	904,293	40,406	354,999	5,188,031	13,538	14,494,695	4,705,811	1,573,584	251,875	31,188	21,465	45,976,095	1,514,731	10,404	12,377	2,887	661	32,837
13																				
14	**TARGET REVENUE REQUIREMENTS (EQUALIZED)**																			
15	Equalized Base Revenue Requirements	11,162,674	137,181	6,044	54,504	757,274	2,026	2,181,306	712,006	240,935	38,243	4,536	3,136	6,815,755	201,996	1,536	1,758	437	67	3,934
16	Other Operating Revenues	266,875	2,169	93	655	18,716	37	35,860	11,352	3,885	785	74	101	191,032	1,948	35	45	16	3	69
17	**Total Target Revenue Requirements**	11,429,549	139,349	6,137	55,159	775,990	2,063	2,217,166	723,358	244,821	39,028	4,610	3,237	7,006,787	203,944	1,571	1,803	453	69	4,003
18																				
19	**EXPENSES -**																			
20	Operating & Maintenance Expense	(1,324,273)	(16,250)	(699)	(7,362)	(94,815)	(358)	(237,177)	(79,465)	(27,421)	(4,966)	(520)	(243)	(839,255)	(14,556)	(244)	(247)	(97)	(8)	(590)
21	Depreciation Expense	(3,081,922)	(36,089)	(1,623)	(14,611)	(215,311)	(601)	(586,651)	(187,453)	(62,600)	(10,337)	(1,294)	(820)	(1,910,065)	(52,072)	(411)	(486)	(130)	(31)	(1,337)
22	Taxes Other Than Income Tax	(903,354)	(10,768)	(482)	(4,167)	(62,430)	(163)	(173,472)	(56,204)	(18,761)	(2,964)	(373)	(264)	(553,853)	(18,746)	(125)	(148)	(35)	(8)	(388)
23	Amortization of Property Losses	(15,639)	(195)	(8)	(95)	(1,119)	(4)	(2,954)	(973)	(335)	(66)	(6)	(2)	(9,779)	(88)	(2)	(3)	(1)	(0)	(8)
24	Gain or Loss on Sale of Plant	420	5	0		29	0	85	29	9		0	0	260	2	0	0	0	0	
25	**Total Operating Expenses**	(5,324,768)	(63,298)	(2,813)	(26,236)	(373,646)	(1,126)	(1,000,170)	(324,067)	(109,108)	(18,332)	(2,194)	(1,328)	(3,312,693)	(85,459)	(782)	(884)	(263)	(48)	(2,323)
26																				
27	**Net Operating Income Before Taxes**	6,104,781	76,052	3,324	28,924	402,344	937	1,216,996	399,292	135,713	20,696	2,416	1,909	3,694,094	118,485	788	919	190	22	1,680
28	Income Taxes	(372,827)	(7,055)	(241)	(1,837)	(6,504)	96	(111,067)	(40,489)	(15,755)	(1,478)	(37)	(271)	(186,184)	(2,921)	6	25	30	29	826
29	**NOI Before Curtailment Adjustment**	5,731,953	68,997	3,083	27,087	395,840	1,033	1,105,929	358,803	119,958	19,218	2,380	1,638	3,507,910	115,565	794	944	220	50	2,505
30																				
31	Curtailment Credit Revenue	469							329	141										
32	Reassign Curtailment Credit Revenue	(469)	(6)	(0)	(3)	(33)	(0)	(96)	(31)	(11)	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
33	Net Curtailment Credit Revenue	0	(6)	(0)	(3)	(33)	(0)	(96)	298	130	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
34	Net Curtailment NOI Adjustment	0	(5)	(0)	(2)	(25)	(0)	(72)	222	97	(2)	(0)	(0)	(213)		(0)	(0)	(0)	(0)	(0)
35																				
36	**Net Operating Income (NOI)**	5,731,953	68,992	3,083	27,084	395,815	1,033	1,105,857	359,025	120,055	19,217	2,379	1,638	3,507,697	115,565	794	944	220	50	2,505
37																				
38	**Equalized Rate of Return (ROR)**	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%
39																				
40	**TARGET REVENUE REQUIREMENTS DEFICIENCY**																			
41	Base Revenue Requirements	1,545,221	28,894	994	7,589	29,321	(377)	455,126	165,551	64,250	6,083	167	1,105	777,344	12,820	(17)	(93)	(128)	(114)	(3,295)
42	Other Operating Revenues	(441)	0	0	0	53	1	30	2	0	0	0	0	(537)	0	0	1	7	0	0
43	**Target Revenue Requirements Deficiency**	1,544,780	28,895	994	7,589	29,374	(375)	455,156	165,553	64,251	6,083	167	1,105	776,807	12,820	(16)	(92)	(120)	(114)	(3,295)
44																				
45	**TARGET REVENUE REQUIREMENTS INDEX** [2]																			

46
47 [1] Target Revenue Requirements at proposed ROR less
48 Total Revenues at present rates from Attachment 1.
49 [2] Total Revenues at present rates from Attachment 1
50 divided by Target Revenue Requirements.
51
52 Note: Totals may not add due to rounding.

Equalized Revenue Requirement (ASK)		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
	75,129,876	904,293	40,406	354,999	5,188,031	13,538	14,494,695	4,705,811	1,573,584	251,875	31,188	21,465	45,976,095	1,514,731	10,404	12,377	2,887	661	32,837
Requested ROR VIA A-1	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%	7.63%
NOI Requested	5,731,953	68,992	3,083	27,084	395,815	1,033	1,105,857	359,025	120,055	19,217	2,379	1,638	3,507,697	115,565	794	944	220	50	2,505
Achieved NOI	4,580,123	47,447	2,342	21,426	373,913	1,313	766,480	235,584	72,148	14,681	2,255	814	2,928,488	106,006	806	1,013	310	136	4,962
Deficency	1,151,831	21,545	741	5,658	21,902	(280)	339,377	123,441	47,907	4,536	125	824	579,209	9,559	(12)	(69)	(90)	(85)	(2,457)
NOI Mulitplier	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Total Requested Increase	1,544,780	28,895	994	7,589	29,374	(375)	455,156	165,553	64,251	6,083	167	1,105	776,807	12,820	(16)	(92)	(120)	(114)	(3,295)

Tax Calculation		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
Achieved		259	10	84	931	1	4,150	1,419	510	62	6	8	10,455	325	2	2	(0)	(0)	(9)
Incremental Total Revenue		28,895	994	7,589	29,374	(375)	455,156	165,553	64,251	6,083	167	1,105	776,807	12,820	(16)	(92)	(120)	(114)	(3,295)
State Rate		5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%
Incremental State Taxes		(1,587)	(55)	(417)	(1,614)	21	(25,003)	(9,094)	(3,529)	(334)	(9)	(61)	(42,672)	(704)	1	5	7	6	181
Federal Rate		19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%	19.820%
Incremental Federal Taxes		(5,727)	(197)	(1,504)	(5,822)	74	(90,214)	(32,813)	(12,735)	(1,206)	(33)	(219)	(153,967)	(2,541)	3	18	24	23	653
Total Taxes	(372,827)	(7,055)	(241)	(1,837)	(6,504)	96	(111,067)	(40,489)	(15,755)	(1,478)	(37)	(271)	(186,184)	(2,921)	6	25	30	29	826

FLORIDA POWER AND LIGHT COMPANY
2026 REVISED CLASS COST OF SERVICE STUDY
(4CP PRODUCTION, 1/13 ENERGY ALLOCATOR)

MFR E-1 - COST OF SERVICE STUDY
2026 AT PRESENT RATES
($000 WHERE APPLICABLE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Methodologies: 12CP and 25%	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
1	**RATE BASE -**																			
2	Electric Plant In Service	86,274,360	1,020,661	45,836	390,760	5,988,317	15,855	16,497,481	5,336,757	1,778,600	278,065	35,804	25,038	53,132,955	1,661,618	12,037	13,807	3,434	828	36,508
3	Accum Depreciation & Amortization	(17,683,082)	(202,333)	(9,155)	(75,441)	(1,256,887)	(3,723)	(3,280,272)	(1,057,593)	(351,435)	(53,434)	(7,397)	(4,807)	(11,150,686)	(216,605)	(2,651)	(2,587)	(863)	(205)	(7,008)
4	Net Plant in Service	68,591,278	818,327	36,681	315,319	4,731,429	12,132	13,217,208	4,279,164	1,427,164	224,631	28,407	20,231	41,982,269	1,445,013	9,387	11,220	2,571	624	29,501
5	Plant Held For Future Use	1,475,168	19,631	854	9,745	103,175	236	303,493	99,427	34,104	6,920	643	124	894,385	1,190	110	227	39	3	861
6	Construction Work in Progress	2,012,666	24,086	1,074	9,493	139,263	378	383,942	125,166	41,881	6,703	808	533	1,241,467	36,307	286	332	85	15	847
7	Net Nuclear Fuel	745,109	14,205	574	8,163	49,138	184	170,272	62,731	22,819	5,240	385	82	407,592	2,696	217	180	37	0	593
8	Total Utility Plant	72,824,221	876,251	39,182	342,720	5,023,005	12,930	14,074,915	4,566,487	1,525,968	243,495	30,243	20,970	44,525,713	1,485,207	10,000	11,958	2,733	642	31,802
9	Working Capital - Assets	5,812,779	71,258	3,088	31,667	415,221	1,526	1,054,439	351,546	120,657	21,497	2,341	1,187	3,662,004	71,181	1,043	1,068	398	42	2,616
10	Working Capital - Liabilities	(3,507,123)	(43,216)	(1,865)	(19,389)	(250,195)	(918)	(634,658)	(212,222)	(73,041)	(13,116)	(1,396)	(692)	(2,211,621)	(41,656)	(639)	(649)	(244)	(23)	(1,582)
11	Working Capital - Net	2,305,655	28,042	1,223	12,279	165,026	608	419,780	139,324	47,616	8,381	945	495	1,450,382	29,524	404	419	154	19	1,034
12	**Total Rate Base**	75,129,876	904,293	40,406	354,999	5,188,031	13,538	14,494,695	4,705,811	1,573,584	251,875	31,188	21,465	45,976,095	1,514,731	10,404	12,377	2,887	661	32,837
13																				
14	**REVENUES -**																			
15	Sales of Electricity	9,617,453	108,286	5,050	46,915	727,953	2,403	1,726,181	546,455	176,685	32,160	4,368	2,031	6,038,411	189,177	1,552	1,851	564	181	7,229
16	Other Operating Revenues	267,316	2,168	93	655	18,663	36	35,830	11,350	3,885	785	74	101	191,569	1,947	34	44	9	3	69
17	**Total Operating Revenues**	9,884,769	110,454	5,143	47,570	746,616	2,439	1,762,010	557,805	180,570	32,945	4,443	2,132	6,229,980	191,124	1,587	1,895	573	184	7,299
18																				
19	**EXPENSES -**																			
20	Operating & Maintenance Expense	(1,322,364)	(16,214)	(698)	(7,353)	(94,778)	(359)	(236,615)	(79,261)	(27,342)	(4,958)	(520)	(242)	(838,295)	(14,540)	(244)	(247)	(97)	(8)	(594)
21	Depreciation Expense	(3,081,922)	(36,089)	(1,623)	(14,611)	(215,311)	(601)	(586,651)	(187,453)	(62,600)	(10,337)	(1,294)	(820)	(1,910,065)	(52,072)	(411)	(486)	(130)	(31)	(1,337)
22	Taxes Other Than Income Tax	(903,354)	(10,768)	(482)	(4,167)	(62,430)	(163)	(173,472)	(56,204)	(18,761)	(2,964)	(373)	(264)	(553,853)	(18,746)	(125)	(148)	(35)	(8)	(388)
23	Amortization of Property Losses	(15,639)	(195)	(8)	(95)	(1,119)	(4)	(2,954)	(973)	(335)	(66)	(6)	(2)	(9,779)	(88)	(2)	(3)	(1)	(0)	(8)
24	Gain or Loss on Sale of Plant	420	5	0		29	0	85	29	9		0	0	260	2	0	0	0	0	
25	**Total Operating Expenses**	(5,322,859)	(63,262)	(2,811)	(26,226)	(373,610)	(1,127)	(999,607)	(323,862)	(109,029)	(18,325)	(2,193)	(1,327)	(3,311,733)	(85,443)	(783)	(884)	(263)	(48)	(2,327)
26																				
27	**Net Operating Income Before Taxes**	4,561,910	47,193	2,332	21,344	373,006	1,312	762,403	233,943	71,541	14,620	2,249	806	2,918,247	105,681	804	1,011	310	136	4,971
28	Income Taxes	18,213	259	10	84	931	1	4,150	1,419	510	62	6	8	10,455	325	2	2	(0)	(0)	(9)
29	**NOI Before Curtailment Adjustment**	4,580,123	47,452	2,342	21,428	373,938	1,313	766,552	235,362	72,051	14,683	2,255	814	2,928,701	106,006	806	1,013	310	136	4,963
30																				
31	Curtailment Credit Revenue	469							329	141										
32	Reassign Curtailment Credit Revenue	(469)	(6)	(0)	(3)	(33)	(0)	(96)	(31)	(11)	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
33	Net Curtailment Credit Revenue	0	(6)	(0)	(3)	(33)	(0)	(96)	298	130	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
34	Net Curtailment NOI Adjustment	0	(5)	(0)	(2)	(25)	(0)	(72)	222	97	(2)	(0)	(0)	(213)		(0)	(0)	(0)	(0)	(0)
35																				
36	**Net Operating Income (NOI)**	4,580,123	47,447	2,342	21,426	373,913	1,313	766,480	235,584	72,148	14,681	2,255	814	2,928,488	106,006	806	1,013	310	136	4,962
37																				
38	**Rate of Return (ROR)**	6.10%	5.25%	5.80%	6.04%	7.21%	9.70%	5.29%	5.01%	4.58%	5.83%	7.23%	3.79%	6.37%	7.00%	7.75%	8.18%	10.74%	20.55%	15.11%
39																				
40	**Parity at Present Rates**	1.000	0.861	0.951	0.990	1.182	1.591	0.867	0.821	0.752	0.956	1.186	0.622	1.045	1.148	1.271	1.342	1.761	3.370	2.479
41																				
42	**EQUALIZED RATE OF RETURN (ROR) -**																			
43	Equalized Base Revenue Requirements	9,617,453	116,002	5,172	47,126	669,965	1,913	1,843,900	598,251	200,692	32,834	4,013	2,529	5,911,847	175,471	1,380	1,591	430	85	4,252
44	Other Operating Revenues	267,316	2,168	93	655	18,663	36	35,830	11,350	3,885	785	74	101	191,569	1,947	34	44	9	3	69
45	**Total Equalized Revenue Requirements**	9,884,769	118,171	5,265	47,782	688,628	1,949	1,879,730	609,601	204,577	33,619	4,087	2,630	6,103,416	177,418	1,414	1,635	438	88	4,321
46																				
47	**Revenue Requirements Deficiency (Excess)**	0	7,716	122	212	(57,987)	(490)	117,720	51,795	24,007	674	(355)	498	(126,564)	(13,706)	(173)	(260)	(135)	(96)	(2,977)
48																				
49	**Revenue Requirements Index** [1]		93.5%	97.7%	99.6%	108.4%	125.2%	93.7%	91.5%	88.3%	98.0%	108.7%	81.1%	102.1%	107.7%	112.2%	115.9%	130.7%	209.2%	168.9%
50																				
51	[1] Total Revenues divided by Total																			
52	Equalized Revenue Requirements																			
53																				
54	Note: Totals may not add due to rounding.																			

Equalization Calculation

		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
Eqalized ROR	6.10%																		
Equalized NOI	4,580,123	55,128	2,463	21,642	316,277	825	883,636	286,879	95,930	15,355	1,901	1,309	2,802,829	92,342	634	755	176	40	2,002
		1.20%	0.05%	0.47%	6.91%	0.02%	19.29%	6.26%	2.09%	0.34%	0.04%	0.03%	61.20%	2.02%	0.01%	0.02%	0.00%	0.00%	0.04%
Income Taxes	18,213	219	10	86	1,258	3	3,514	1,141	381	61	8	5	11,146	367	3	3	1	0	8
Total Equalized Base Revenue Requirement:	9,884,769	118,171	5,265	47,782	688,628	1,949	1,879,730	609,601	204,577	33,619	4,087	2,630	6,103,416	177,418	1,414	1,635	438	88	4,321

FLORIDA POWER AND LIGHT COMPANY
2027 REVISED CLASS COST OF SERVICE STUDY
(4CP PRODUCTION, 1/13 ENERGY ALLOCATOR)

MFR E-1 - COST OF SERVICE STUDY
2027 EQUALIZED AT PROPOSED ROR
($000 WHERE APPLICABLE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Methodologies: 12CP and 25%	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
1	**RATE BASE -**																			
2	Electric Plant In Service	93,279,289	1,093,998	49,039	426,971	6,473,466	17,017	17,824,874	5,703,796	1,915,774	303,600	38,441	25,746	57,466,628	1,867,326	13,382	14,821	3,898	859	39,654
3	Accum Depreciation & Amortization	(19,515,489)	(221,923)	(10,026)	(83,951)	(1,385,774)	(4,034)	(3,636,189)	(1,157,817)	(387,536)	(59,458)	(8,121)	(5,185)	(12,307,748)	(232,939)	(3,016)	(2,809)	(980)	(220)	(7,763)
4	Net Plant in Service	73,763,800	872,075	39,012	343,020	5,087,692	12,983	14,188,684	4,545,979	1,528,237	244,142	30,319	20,561	45,158,879	1,634,387	10,366	12,012	2,918	640	31,891
5	Plant Held For Future Use	1,533,409	20,252	880	10,202	107,258	241	315,879	102,372	35,354	7,243	665	120	930,712	941	115	231	42	2	900
6	Construction Work in Progress	2,119,109	25,131	1,118	10,133	146,803	398	403,571	130,129	43,898	7,151	845	528	1,308,760	38,976	309	347	95	15	901
7	Net Nuclear Fuel	840,565	15,892	641	9,177	55,492	206	192,147	70,064	25,620	5,889	433	92	461,056	2,686	258	199	44	0	667
8	Total Utility Plant	78,256,883	933,350	41,651	372,533	5,397,246	13,828	15,100,281	4,848,545	1,633,109	264,425	32,263	21,301	47,859,408	1,676,991	11,048	12,788	3,100	658	34,359
9	Working Capital - Assets	5,924,815	71,453	3,095	32,030	424,207	1,562	1,068,072	351,938	121,560	21,749	2,363	1,175	3,746,614	73,695	1,106	1,073	434	42	2,648
10	Working Capital - Liabilities	(3,430,118)	(41,678)	(1,797)	(18,863)	(244,980)	(896)	(618,339)	(204,432)	(70,794)	(12,769)	(1,352)	(658)	(2,168,973)	(41,499)	(649)	(626)	(252)	(22)	(1,541)
11	Working Capital - Net	2,494,697	29,775	1,297	13,167	179,227	666	449,733	147,505	50,767	8,981	1,011	517	1,577,642	32,196	457	447	181	21	1,107
12	**Total Rate Base**	80,751,580	963,126	42,948	385,700	5,576,473	14,494	15,550,013	4,996,050	1,683,876	273,406	33,274	21,818	49,437,050	1,709,187	11,505	13,235	3,281	678	35,466
13																				
14	**TARGET REVENUE REQUIREMENTS (EQUALI**																			
15	Equalized Base Revenue Requirements	12,185,857	147,817	6,513	60,037	829,541	2,227	2,370,378	764,663	260,524	42,117	4,932	3,209	7,451,623	233,557	1,721	1,926	516	73	4,484
16	Other Operating Revenues	285,066	2,274	97	691	20,434	40	37,797	11,875	4,087	813	78	103	204,577	2,029	39	46	11	3	73
17	**Total Target Revenue Requirements**	12,470,922	150,091	6,610	60,728	849,975	2,266	2,408,175	776,538	264,611	42,930	5,010	3,312	7,656,199	235,587	1,760	1,972	527	76	4,557
18																				
19	**EXPENSES -**																			
20	Operating & Maintenance Expense	(1,352,759)	(16,370)	(704)	(7,488)	(97,000)	(366)	(241,181)	(79,920)	(27,753)	(5,052)	(526)	(241)	(860,015)	(14,922)	(260)	(249)	(105)	(8)	(600)
21	Depreciation Expense	(3,327,212)	(38,609)	(1,733)	(15,896)	(232,553)	(646)	(632,751)	(199,953)	(67,292)	(11,240)	(1,388)	(845)	(2,063,344)	(58,354)	(457)	(520)	(148)	(33)	(1,450)
22	Taxes Other Than Income Tax	(943,334)	(11,140)	(498)	(4,398)	(65,190)	(170)	(180,812)	(57,968)	(19,503)	(3,125)	(387)	(261)	(578,556)	(20,586)	(134)	(154)	(39)	(8)	(407)
23	Amortization of Property Losses	(16,289)	(200)	(9)	(97)	(1,166)	(4)	(3,065)	(998)	(345)	(68)	(7)	(2)	(10,212)	(102)	(2)	(3)	(1)	(0)	(8)
24	Gain or Loss on Sale of Plant	33	0	0		2	0	7	2	1		0	0	21	0	0	0	0	0	
25	**Total Operating Expenses**	(5,639,559)	(66,318)	(2,943)	(27,880)	(395,906)	(1,186)	(1,057,802)	(338,836)	(114,892)	(19,485)	(2,308)	(1,348)	(3,512,106)	(93,964)	(853)	(926)	(293)	(49)	(2,465)
26																				
27	**Net Operating Income Before Taxes**	6,831,363	83,773	3,667	32,849	454,068	1,080	1,350,373	437,702	149,719	23,446	2,702	1,964	4,144,094	141,623	906	1,046	234	27	2,091
28	Income Taxes	(658,094)	(10,140)	(383)	(3,360)	(27,736)	28	(161,540)	(55,988)	(21,087)	(2,543)	(159)	(296)	(364,534)	(10,959)	(27)	(34)	17	25	620
29	**NOI Before Curtailment Adjustment**	6,173,269	73,633	3,283	29,488	426,333	1,108	1,188,834	381,714	128,631	20,903	2,544	1,668	3,779,560	130,663	880	1,012	251	52	2,711
30																				
31	Curtailment Credit Revenue	469							329	141										
32	Reassign Curtailment Credit Revenue	(469)	(6)	(0)	(3)	(33)	(0)	(96)	(31)	(11)	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
33	Net Curtailment Credit Revenue	(0)	(6)	(0)	(3)	(33)	(0)	(96)	298	130	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
34	Net Curtailment NOI Adjustment	0	(4)	(0)	(2)	(25)	(0)	(72)	222	97	(2)	(0)	(0)	(214)		(0)	(0)	(0)	(0)	(0)
35																				
36	**Net Operating Income (NOI)**	6,173,269	73,629	3,283	29,486	426,308	1,108	1,188,762	381,936	128,728	20,901	2,544	1,668	3,779,346	130,663	880	1,012	251	52	2,711
37																				
38	**Equalized Rate of Return (ROR)**	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
39																				
40	**TARGET REVENUE REQUIREMENTS DEFICIE**																			
41	Base Revenue Requirements	2,471,652	39,303	1,459	12,766	94,783	(177)	624,983	218,246	82,981	9,720	543	1,172	1,348,713	39,972	67	93	(85)	(108)	(2,778)
42	Other Operating Revenues	6,095	0	0	0	923	1	35	2	0	0	0	0	5,123	7	0	0	1	0	0
43	**Target Revenue Requirements Deficiency**	2,477,747	39,303	1,459	12,766	95,706	(176)	625,018	218,248	82,981	9,720	543	1,172	1,353,837	39,980	68	94	(85)	(108)	(2,778)
44																				
45	**TARGET REVENUE REQUIREMENTS INDEX** [2]																			
46																				
47	[1] Target Revenue Requirements at proposed ROR less																			
48	Total Revenues at present rates from Attachment 1.																			
49	[2] Total Revenues at present rates from Attachment 1																			
50	divided by Target Revenue Requirements.																			
51																				
52	Note: Totals may not add due to rounding.																			

Equalized Revenue Requirement (ASK)		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
	80,751,580	963,126	42,948	385,700	5,576,473	14,494	15,550,013	4,996,050	1,683,876	273,406	33,274	21,818	49,437,050	1,709,187	11,505	13,235	3,281	678	35,466
Requested ROR VIA A-1	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%	7.64%
NOI Requested	6,173,269	73,629	3,283	29,486	426,308	1,108	1,188,762	381,936	128,728	20,901	2,544	1,668	3,779,346	130,663	880	1,012	251	52	2,711
Achieved NOI	4,325,766	44,323	2,196	19,967	354,946	1,239	722,725	219,202	66,854	13,654	2,139	794	2,769,874	100,853	829	942	314	133	4,782
Deficency	1,847,502	29,306	1,088	9,518	71,362	(131)	466,037	162,734	61,874	7,248	405	874	1,009,472	29,810	50	70	(63)	(81)	(2,071)
NOI Mulitplier	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34	1.34
Total Requested Increase	2,477,747	39,303	1,459	12,766	95,706	(176)	625,018	218,248	82,981	9,720	543	1,172	1,353,837	39,980	68	94	(85)	(108)	(2,778)

Tax Calculation		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
Achieved		(191)	(14)	(129)	(3,509)	(17)	(3,322)	(740)	(82)	(82)	(21)	1	(21,823)	(839)	(10)	(10)	(5)	(3)	(83)
Incremental Total Revenue		39,303	1,459	12,766	95,706	(176)	625,018	218,248	82,981	9,720	543	1,172	1,353,837	39,980	68	94	(85)	(108)	(2,778)
State Rate		5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%	5.493%
Incremental State Taxes		(2,159)	(80)	(701)	(5,257)	10	(34,334)	(11,989)	(4,558)	(534)	(30)	(64)	(74,370)	(2,196)	(4)	(5)	5	6	153
Federal Rate		19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%	19.821%
Incremental Federal Taxes		(7,790)	(289)	(2,530)	(18,970)	35	(123,883)	(43,258)	(16,448)	(1,927)	(108)	(232)	(268,341)	(7,924)	(13)	(19)	17	21	551
Total Taxes	(658,094)	(10,140)	(383)	(3,360)	(27,736)	28	(161,540)	(55,988)	(21,087)	(2,543)	(159)	(296)	(364,534)	(10,959)	(27)	(34)	17	25	620

FLORIDA POWER AND LIGHT COMPANY
2027 REVISED CLASS COST OF SERVICE STUDY
(4CP PRODUCTION, 1/13 ENERGY ALLOCATOR)

MFR E-1 - COST OF SERVICE STUDY
2027 AT PRESENT RATES
($000 WHERE APPLICABLE)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Methodologies: 12CP and 25%	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
1	**RATE BASE -**																			
2	Electric Plant In Service	93,279,289	1,093,998	49,039	426,971	6,473,466	17,017	17,824,874	5,703,796	1,915,774	303,600	38,441	25,746	57,466,628	1,867,326	13,382	14,821	3,898	859	39,654
3	Accum Depreciation & Amortization	(19,515,489)	(221,923)	(10,026)	(83,951)	(1,385,774)	(4,034)	(3,636,189)	(1,157,817)	(387,536)	(59,458)	(8,121)	(5,185)	(12,307,748)	(232,939)	(3,016)	(2,809)	(980)	(220)	(7,763)
4	Net Plant in Service	73,763,800	872,075	39,012	343,020	5,087,692	12,983	14,188,684	4,545,979	1,528,237	244,142	30,319	20,561	45,158,879	1,634,387	10,366	12,012	2,918	640	31,891
5	Plant Held For Future Use	1,533,409	20,252	880	10,202	107,258	241	315,879	102,372	35,354	7,243	665	120	930,712	941	115	231	42	2	900
6	Construction Work in Progress	2,119,109	25,131	1,118	10,133	146,803	398	403,571	130,129	43,898	7,151	845	528	1,308,760	38,976	309	347	95	15	901
7	Net Nuclear Fuel	840,565	15,892	641	9,177	55,492	206	192,147	70,064	25,620	5,889	433	92	461,056	2,686	258	199	44	0	667
8	Total Utility Plant	78,256,883	933,350	41,651	372,533	5,397,246	13,828	15,100,281	4,848,545	1,633,109	264,425	32,263	21,301	47,859,408	1,676,991	11,048	12,788	3,100	658	34,359
9	Working Capital - Assets	5,924,815	71,453	3,095	32,030	424,207	1,562	1,068,072	351,938	121,560	21,749	2,363	1,175	3,746,614	73,695	1,106	1,073	434	42	2,648
10	Working Capital - Liabilities	(3,430,118)	(41,678)	(1,797)	(18,863)	(244,980)	(896)	(618,339)	(204,432)	(70,794)	(12,769)	(1,352)	(658)	(2,168,973)	(41,499)	(649)	(626)	(252)	(22)	(1,541)
11	Working Capital - Net	2,494,697	29,775	1,297	13,167	179,227	666	449,733	147,505	50,767	8,981	1,011	517	1,577,642	32,196	457	447	181	21	1,107
12	**Total Rate Base**	80,751,580	963,126	42,948	385,700	5,576,473	14,494	15,550,013	4,996,050	1,683,876	273,406	33,274	21,818	49,437,050	1,709,187	11,505	13,235	3,281	678	35,466
13																				
14	**REVENUES -**																			
15	Sales of Electricity	9,714,204	108,514	5,054	47,272	734,758	2,403	1,745,395	546,417	177,543	32,398	4,389	2,037	6,102,909	193,585	1,653	1,832	601	181	7,262
16	Other Operating Revenues	278,971	2,274	97	691	19,511	38	37,762	11,873	4,087	812	78	102	199,453	2,022	39	46	10	3	73
17	**Total Operating Revenues**	9,993,175	110,788	5,151	47,963	754,269	2,442	1,783,157	558,290	181,630	33,210	4,467	2,140	6,302,363	195,607	1,692	1,878	612	184	7,334
18																				
19	**EXPENSES -**																			
20	Operating & Maintenance Expense	(1,349,732)	(16,322)	(702)	(7,473)	(96,883)	(366)	(240,417)	(79,653)	(27,652)	(5,040)	(526)	(239)	(858,361)	(14,873)	(260)	(248)	(105)	(8)	(604)
21	Depreciation Expense	(3,327,212)	(38,609)	(1,733)	(15,896)	(232,553)	(646)	(632,751)	(199,953)	(67,292)	(11,240)	(1,388)	(845)	(2,063,344)	(58,354)	(457)	(520)	(148)	(33)	(1,450)
22	Taxes Other Than Income Tax	(943,334)	(11,140)	(498)	(4,398)	(65,190)	(170)	(180,812)	(57,968)	(19,503)	(3,125)	(387)	(261)	(578,556)	(20,586)	(134)	(154)	(39)	(8)	(407)
23	Amortization of Property Losses	(16,289)	(200)	(9)	(97)	(1,166)	(4)	(3,065)	(998)	(345)	(68)	(7)	(2)	(10,212)	(102)	(2)	(3)	(1)	(0)	(8)
24	Gain or Loss on Sale of Plant	33	0	0		2	0	7	2	1		0	0	21	0	0	0	0	0	
25	**Total Operating Expenses**	(5,636,532)	(66,270)	(2,941)	(27,864)	(395,789)	(1,186)	(1,057,038)	(338,569)	(114,791)	(19,473)	(2,307)	(1,347)	(3,510,452)	(93,915)	(853)	(925)	(293)	(49)	(2,469)
26																				
27	**Net Operating Income Before Taxes**	4,356,643	44,518	2,210	20,099	358,479	1,255	726,119	219,721	66,839	13,738	2,160	793	2,791,911	101,692	839	953	319	135	4,866
28	Income Taxes	(30,877)	(191)	(14)	(129)	(3,509)	(17)	(3,322)	(740)	(82)	(82)	(21)	1	(21,823)	(839)	(10)	(10)	(5)	(3)	(83)
29	**NOI Before Curtailment Adjustment**	4,325,766	44,327	2,196	19,970	354,971	1,239	722,796	218,980	66,757	13,655	2,139	794	2,770,088	100,853	829	942	314	133	4,783
30																				
31	Curtailment Credit Revenue	469							329	141										
32	Reassign Curtailment Credit Revenue	(469)	(6)	(0)	(3)	(33)	(0)	(96)	(31)	(11)	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
33	Net Curtailment Credit Revenue	(0)	(6)	(0)	(3)	(33)	(0)	(96)	298	130	(2)	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
34	Net Curtailment NOI Adjustment	0	(4)	(0)	(2)	(25)	(0)	(72)	222	97	(2)	(0)	(0)	(214)		(0)	(0)	(0)	(0)	(0)
35																				
36	**Net Operating Income (NOI)**	4,325,766	44,323	2,196	19,967	354,946	1,239	722,725	219,202	66,854	13,654	2,139	794	2,769,874	100,853	829	942	314	133	4,782
37																				
38	**Rate of Return (ROR)**	5.36%	4.60%	5.11%	5.18%	6.37%	8.55%	4.65%	4.39%	3.97%	4.99%	6.43%	3.64%	5.60%	5.90%	7.21%	7.12%	9.57%	19.55%	13.48%
39																				
40	**Parity at Present Rates**	1.000	0.859	0.954	0.966	1.188	1.596	0.868	0.819	0.741	0.932	1.200	0.680	1.046	1.102	1.345	1.329	1.787	3.650	2.517
41																				
42	**EQUALIZED RATE OF RETURN (ROR) -**																			
43	Equalized Base Revenue Requirements	9,714,204	115,958	5,161	47,982	677,136	1,930	1,858,218	596,239	201,551	33,411	4,024	2,421	5,978,186	184,106	1,435	1,594	460	83	4,310
44	Other Operating Revenues	278,971	2,274	97	691	19,511	38	37,762	11,873	4,087	812	78	102	199,453	2,022	39	46	10	3	73
45	**Total Equalized Revenue Requirements**	9,993,175	118,232	5,259	48,673	696,647	1,968	1,895,980	608,112	205,638	34,223	4,102	2,524	6,177,639	186,128	1,474	1,639	470	86	4,382
46																				
47	**Revenue Requirements Deficiency (Excess)**	(0)	7,444	108	710	(57,622)	(473)	112,823	49,822	24,008	1,013	(364)	384	(124,724)	(9,479)	(218)	(239)	(142)	(99)	(2,952)
48																				
49	**Revenue Requirements Index** [1]		93.7%	98.0%	98.5%	108.3%	124.1%	94.0%	91.8%	88.3%	97.0%	108.9%	84.8%	102.0%	105.1%	114.8%	114.5%	130.1%	214.9%	167.4%
50																				
51	[1] Total Revenues divided by Total																			
52	Equalized Revenue Requirements																			
53																				
54	Note: Totals may not add due to rounding.																			

Equalization Calculation

		CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
Eqalized ROR	5.36%																		
Equalized NOI	4,325,766	51,594	2,301	20,661	298,725	776	832,996	267,632	90,203	14,646	1,782	1,169	2,648,284	91,559	616	709	176	36	1,900
		1.19%	0.05%	0.48%	6.91%	0.02%	19.26%	6.19%	2.09%	0.34%	0.04%	0.03%	61.22%	2.12%	0.01%	0.02%	0.00%	0.00%	0.04%
Income Taxes	(30,877)	(368)	(16)	(147)	(2,132)	(6)	(5,946)	(1,910)	(644)	(105)	(13)	(8)	(18,903)	(654)	(4)	(5)	(1)	(0)	(14)
Total Equalized Base Revenue Requirements	9,993,175	118,232	5,259	48,673	696,647	1,968	1,895,980	608,112	205,638	34,223	4,102	2,524	6,177,639	186,128	1,474	1,639	470	86	4,382

FLORIDA POWER AND LIGHT COMPANY
RENEWABLE RESOURCES NAMEPLATE AND ACCREDITED CAPACITY

	FPL System Renewables Firm Capacity Value (FCV)												
	Incremental				Cumulative						Total		
	Solar		Battery		Solar			Battery			Renewable FCV		
Year	Nameplate (MW)	(%)	Nameplate (MW)	(%)	Nameplate (MW)	Firm (MW)	(%)	Nameplate (MW)	Firm (MW)	(%)	Nameplate (MW)	Firm (MW)	(%)
2021	820	50%	0	0%	3,164	1,419	45%	0	0	0%	3,164	1,419	45%
2022	447	38%	469	100%	3,611	1,589	44%	469	469	100%	4,080	2,058	57%
2023	1,192	43%	0	100%	4,803	2,107	44%	469	469	100%	5,272	2,576	54%
2024	2,235	46%	0	100%	7,038	3,137	45%	469	469	100%	7,507	3,606	52%
2025	894	30%	522	67%	7,932	3,406	43%	991	818	83%	8,923	4,224	51%
2026	894	13%	1,420	80%	8,826	3,518	40%	2,410	1,954	81%	11,236	5,472	55%
2027	1,192	5%	820	123%	10,018	3,582	36%	3,230	2,965	92%	13,248	6,547	61%
2028	1,490	5%	596	50%	11,508	3,661	32%	3,826	3,263	85%	15,334	6,924	57%
2029	1,788	5%	596	42%	13,296	3,756	28%	4,422	3,511	79%	17,718	7,267	53%
2030	2,235	5%	596	41%	15,531	3,874	25%	5,018	3,755	75%	20,549	7,630	50%
2031	2,235	5%	596	41%	17,766	3,993	22%	5,614	3,999	71%	23,380	7,993	47%
2032	2,235	5%	0	0%	20,001	4,112	21%	5,614	3,999	71%	25,615	8,111	46%
2033	2,235	5%	1,192	36%	22,236	4,230	19%	6,806	4,423	65%	29,042	8,653	43%
2034	2,235	5%	1,267	28%	24,471	4,349	18%	8,072	4,777	59%	32,543	9,126	39%

Notes:
The table displays the Summer Firm Capacity Values (FCV) for solar and battery. Winter FCV for battery is assumed 100%, and Winter FCV for solar is assumed to be less than 2%.

Source:
Florida Power & Light Company
Docket No. 20250011-EI
FEA's Third Production Request for Documents
Request No. 31
Page 1 of 1

CERTIFICATE OF SERVICE
Docket Nos. 20250011-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail this 9th day of June, 2025, to the following:

Florida Public Service Commission **Office of the General Counsel** Timothy Sparks Shaw Stiller 2540 Shumard Oak Boulevard Tallahassee, Florida 32399 tsparks@psc.state.fl.us SStiller@psc.state.fl.us	**Florida Power & Light Company** Kenneth A. Hoffman John T. Burnett 134 West Jefferson Street Tallahassee, Florida 32301 Ken.hoffman@fpl.com John.T.Burnett@fpl.com
Earthjustice **Florida Rising, Inc.** **LULAC Florida, Inc.** **Environmental Confederation of Southwest Florida, Inc.** Bradley Marshall Jordan Luebkemann 111 S. Martin Luther King Jr. Blvd. Tallahassee, Florida 32301 bmarshall@earthjustice.org jluebkemann@earthjustice.org flcaseupdates@earthjustice.org discovery-gcl@psc.state.fl.us	**Florida Retail Federation** James W. Brew Laura Baker Joseph R. Briscar Sarah B. Newman Stone Mattheis Xenopoulos & Brew, PC 1025 Thomas Jefferson St., N.W., Ste 800 West Washington, DC 20007 jbrew@smxblaw.com lwb@smxblaw.com jrb@smxblaw.com sbn@smxblaw.com
Office of Public Counsel Mary A. Wessling Walt Trierweiler c/o The Florida Legislature 111 West Madison Street, Room 812 Tallahassee, FL 32399 Wessling.mary@leg.state.fl.us Trierweiler.walt@leg.state.fl.us	**Southern Alliance for Clean Energy** William C. Garner Law Office of William C. Garner, PLLC 3425 Bannerman Road Unit 105, No. 414 Tallahassee, FL 32312 bgarner@wcglawoffice.com
Florida Industrial Power Users Group Jon C. Moyle, Jr. Karen A. Putnal Moyle Law Finn, P.A. 118 North Gadsden Street Tallahassee, Florida 32301 jmoyle@moylelaw.com	**Walmart** Stephanie U. Eaton 110 Oakwood Dr. Ste. 500 Winston-Salem, NC 27103 Steven W. Lee 1100 Bent Creek Blvd, Ste.101

kputnal@moylelaw.com mqualls@moylelaw.com	Mechanicsburg, PA 17050 seaton@spilmanlaw.com slee@spilmanlaw.com
Electrify America, LLC Stephen Bright Jigar J. Shah 1950 Opportunity Way, Suite 1500 Reston, Virginia 20190 Phone: (781) 206-7979 Steve.Bright@electrifyamerica.com Jigar.Shah@electrifyamerica.com Robert E. Montejo, Esq. Duane Morris LLP 201 S. Biscayne Boulevard, Suite 3400 Miami, Florida 33131-4325 Phone: (202) 776-7827 REMontejo@duanemorris.com	**Florida Energy for Innovation Association (FEIA)** D. Bruce May Kevin W. Cox Kathryn Isted Holland & Knight LLP 315 South Calhoun Street, Suite 600 Tallahassee, Florida 32301 (850) 224-7000 Bruce.may@hklaw.com Kevin.cox@hklaw.com Kathryn.isted@hklaw.com
League of United Latin American Citizens of Florida (LULAC) Danielle McManamon 4500 Biscayne Blvd. Ste. 201 Miami, FL 33137 dmcmanamon@earthjustic.org fleaseupdates@earthjustice.org	**Americans for Affordable Clean Energy (AACE)** Floyd Self 313 N. Monroe Street, Ste. 301 Tallahassee, FL 32301 fself@bergersingerman.com
Floridians Against Increased Rates (FAIR) Robert Scheffel Rhoda Dulgar 1300 Thomaswood Dr. Tallahassee, FL 32308 schef@gbwlegal.com rhonda@gbwlegal.com	**Federal Executive Agencies** Leslie Newton Ashley George Michael Rivera Thomas Jernigan Ebony M. Payton James Ely AFLOA/JAOE-ULFSC 139 Barnes Drive, Suite 1 Tyndall Air Force Base, FL 32403 Leslie.Newton.1@us.af.mil Ashley.George.4@us.af.mil Michael.Rivera.51@us.af.mil Thomas.Jernigan.3@us.af.mil Ebony.Payton.ctr@us.af.mil James.Ely@us.af.mil

/s/ Ebony M. Payton
Ebony M. Payton
Paralegal for FEA