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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition by Florida Power & Light Company for Base Rate Increase	**DOCKET NO. 20250011-EI** **Filed: June 9, 2025**

CONFIDENTIAL INFORMATION REDACTED

DIRECT TESTIMONY AND EXHIBITS OF JONATHAN LY

ON BEHALF OF
THE FLORIDA INDUSTRIAL POWER USERS GROUP

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LIST OF EXHIBITS

GLOSSARY OF ACRONYMS

Term	Definition
4CP	Four Coincident Peak
12CP	Twelve Coincident Peak
AD	Average Demand
CCOSS	Class Cost-of-Service Study
CILC	Commercial/Industrial Load Control
CDR	Commercial/Industrial Demand Reduction
CPR	Capacity Payment Recovery
CPVRR	Cumulative Present Value Revenue Requirement
ECCR	Energy Conservation Cost Recovery
FPL	Florida Power & Light Company
FIPUG	Florida Industrial Power Users Group
ITC	Investment Tax Credit
kW	Kilowatt
MW	Megawatts
O&M	Operation and Maintenance
TECO	Tampa Electric Company
RIM	Rate Impact Measurement
T&D	Transmission and Distribution

Direct Testimony of Jonathan Ly

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly, 14323 South Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an Associate of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I have a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley and a Master's degree in Energy and Earth Resources from the University of Texas at Austin. Since joining J. Pollock, Incorporated in 2018, I have participated in numerous regulatory proceedings regarding the ratemaking process, resource planning, certificates of convenience and necessity, and assessments of planned new resources in Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming. My qualifications are documented in **Appendix A**. A list of my appearances in utility regulatory proceedings is provided in **Appendix B**.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Florida Industrial Power Users Group (FIPUG). A substantial number of FIPUG members purchase electricity from Florida Power & Light Company (FPL). They are among the largest FPL customers and consume significant quantities of electricity, often around-the-clock, and require a reliable, affordablypriced supply of electricity to power their operations. Therefore, FIPUG members have a direct and substantial interest in the issues raised in, and the outcome of, this proceeding. FIPUG has been actively participating and representing its members interests for decades in legal proceedings, including FPL rate case proceedings, before the Commission and the Florida Supreme Court.

Q **WHAT ISSUES DO YOU ADDRESS?**

A I sponsor FIPUG's revised class cost-of-service study (CCOSS) that will better reflect cost causation by incorporating changes recommended by my colleague, Mr. Jeffry Pollock, as well as additional changes that I discuss herein. In addition, I also address FPL's proposal to decrease the level of incentives provided to the Commercial/Industrial Load Control (CILC) and Commercial/Industrial Demand Reduction (CDR) customers.

Q **ARE THERE ANY OTHER WITNESSES TESTIFYING ON BEHALF OF FLORIDA INDUSTRIAL POWER USERS GROUP?**

A Yes. My colleague, Mr. Pollock, provides an overview of the drivers of FPL's proposed base revenue increases and requested return on equity, and addresses specific issues regarding FPL's CCOSS and class revenue allocation. In addition, he discusses FPL's proposed changes to its Contribution in Aid of Construction policy and its proposed new rate schedule for Large Load Contract Service.

Q **ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?**

A Yes. I am sponsoring **Exhibits JL-1** through **JL-3**.

Q ARE YOU ACCEPTING FPL'S POSITIONS ON THE ISSUES NOT ADDRESSED IN YOUR DIRECT TESTIMONY?

A No. One should not interpret the fact that I do not address every issue raised by FPL as support of its proposals.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A My findings and recommendations are as follows:

Class Cost-of-Service Study

- Based on Mr. Pollock's testimony, I revised FPL's CCOSS to use the Four Coincident Peak (4CP) method to allocate production and transmission plant and related expenses using the allocation factors derived in **Exhibit JL-1**.
- As shown in **Exhibit JL-2**, I have also modified the 4CP allocation factors to exclude non-firm demand to compensate the CILC/CDR customers for the cost of the CILC/CDR incentives (or interruptible credits) that they are charged under the Energy Conservation Cost Recovery clause. This adjustment is discussed further in Mr. Pollock's testimony.
- FPL allocates various rate base and net operating income costs using either total operation and maintenance (O&M) or O&M Labor expenses extensively throughout its CCOSS. In several instances, O&M or O&M Labor allocators are not reflective of how these costs are incurred. Furthermore, certain other cost components that were not allocated on total O&M or O&M Labor were also allocated in a manner inconsistent with cost causation. As a result, I recommend that changes be made to specific cost components to better reflect cost causation.
- I recommend that the Commission approve FIPUG's revised CCOSS presented in **Exhibit JL-3** incorporating the changes proposed by Mr. Pollock and me.

CILC/CDR Incentive Level

- The CILC and CDR programs provide value to FPL's system as cost-effective demand-side resources that are capable of deferring capacity resource additions.

- Despite analysis demonstrating that the CILC and CDR programs are projected to remain cost-effective at the current rate, FPL is proposing to reduce the incentives paid to program participants by 29%.

- FPL's proposal to reduce the credit is based upon flawed analysis which modeled FPL on a standalone basis, akin to an islanded system that is unable to rely upon generation and transmission capabilities from neighboring utilities, which results in the CILC and CDR programs being called upon with increasing frequency.

- Furthermore, FPL's analysis also assumed that load control periods would always be limited to only six hours. However, under emergency conditions, FPL has the option to extend these periods without constraint. Limiting the ability for these programs to be dispatched in the analysis — while simultaneous relying more frequently on them — understates their actual firm capacity value.

- Based on the historic cost of FPL's installed generation, the 900 megawatts (MW) of existing CILC/CDR load has deferred approximately $591 million of capacity additions.

- The CILC/CDR program will defer the cost of future battery storage additions. Based on FPL's assumed cost of battery storage, the CILC/CDR incentive level can remain cost-effective up to $[redacted] per kilowatt (kW) per month.

- The Commission should reject FPL's proposal to reduce the CILC/CDR incentive level by 29%.

- Instead, the Commission should increase the CILC/CDR incentive level in an amount equivalent to the increase in FPL's production plant in service since its last rate case (40.7%) from $8.76 to $12.32 per kW to recognize its value in deferring future capacity resource additions.

2. CLASS COST-OF-SERVICE STUDY

Q WHAT ROLE DOES COST CAUSATION PLAY IN A COST OF SERVICE STUDY?

A A key tenet of ratemaking is that the customers should pay for the costs that they cause a utility to incur to provide electric service to them. As discussed by Mr. Pollock, a CCOSS is the analysis that is used to determine the extent to which a customer class is responsible for a utility's costs. Therefore, cost causation is the guiding principle of a CCOSS, and the attribution of costs to their cost causers is the ultimate goal of the analysis.

Q HAS THE COMMISSION RECENTLY ISSUED A DECISION CITING THE IMPORTANCE OF COST CAUSATION?

A Yes. In evaluating the allocation of production costs in Tampa Electric Company's (TECO's) most recent base rate case, the Commission stated:

> Moreover, FIPUG and FEA offered testimony supporting 4 CP on the basis that it ***better addresses cost-causation principles by allocating costs to the cost-causer***—the classes responsible for peak demand. Specifically, we are persuaded by the testimony that 4 CP allows TECO to meet system peak demand, which is the cost-causer, while simultaneously allowing TECO to plan for sufficient capacity to meet the expected summer peak and secondary winter peak demand.[1] (emphasis added)

As the Commission appropriately recognized, it is crucial that costs be allocated in a manner reflective of cost causation to ensure that the classes of customers which cause a utility to incur a particular cost pay for the costs that they impose.

[1] *In Re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 20240026-EI, *Final Order Granting in Part and Denying in Part Tampa Electric Company's Petition for Rate Increase* at 128 (Feb. 3, 2025).

Q PLEASE DISCUSS THE REVISED CLASS COST-OF-SERVICE STUDY THAT YOU ARE SPONSORING.

A FIPUG's revised CCOSS includes the changes to FPL's CCOSS as recommended by Mr. Pollock. Specifically:

- Allocate production and transmission demand-related costs using the 4CP method; and
- Adjust the incentive payments to CILC and CDR customers to ensure that the costs are properly allocated to, and recovered from, firm customers who are the sole cost-causers of demand response.

Q ARE THERE ADDITIONAL RECOMMENDED CHANGES REFLECTED IN FIPUG'S REVISED CLASS COST-OF-SERVICE STUDY?

A Yes. First, FPL uses allocation factors based upon total O&M and O&M Labor expenses extensively throughout its CCOSS to allocate the costs of various rate base and net operating income items. However, the use of these factors is not necessarily appropriate for a number of items and changing these allocators as discussed herein more accurately reflects cost causation. Second, although certain other components were not allocated on total O&M or O&M Labor by FPL, they are, nevertheless, allocated in a manner that is unreflective of cost causation. As such, FIPUG's revised CCOSS incorporates specific adjustments to correct these issues.

<u>**4CP Method**</u>

Q HAVE YOU DEVELOPED ALLOCATION FACTORS FOR PRODUCTION AND TRANSMISSION PLANT AND RELATED EXPENSES THAT REFLECT THE 4CP METHOD AS RECOMMENDED BY MR. POLLOCK?

A Yes. As discussed in Mr. Pollock's testimony, FPL is a summer-peaking utility. Based on his recommendation, I have prepared **Exhibit JL-1**, which shows the derivation of

4CP allocation factors based on each class's peak loads in the months of June, July, August, and September.

Q HAVE YOU ALSO DEVELOPED MODIFIED 4CP ALLOCATION FACTORS THAT EXCLUDE NON-FIRM LOAD AS RECOMMENDED BY MR. POLLOCK?

A Yes. As discussed by Mr. Pollock, the costs for interruptible credits should be allocated based only on firm load to rightly recognize the benefits provided by the willingness of non-firm customers to curtail their load in the event of capacity shortage or emergency conditions. Consequently, I have prepared **Exhibit JL-2**, which shows the derivation of the modified 4CP allocation factors which exclude non-firm demand. For CILC classes, firm load was determined by multiplying the class coincident peak load by its firm on-peak billing demand, then dividing this product by the sum of firm on-peak billing demand and the class load control on-peak billing demand. For CDR classes, firm load was determined by removing CDR load from the class maximum demand to determine a ratio of firm load. This ratio of firm load was then multiplied by the class coincident peak demand to identify the amount of firm load at the time of coincident peak. These adjustments are appropriate and fair as FPL customers who voluntarily agree to be interrupted in exchange for compensation should not be required, in effect, to make payments to themselves for being interruptible — which is how the interruptible credits are allocated presently.

<u>Rate Base Components</u>

Q WHAT CHANGES ARE YOU RECOMMENDING TO VARIOUS RATE BASE COMPONENTS?

A A summary of my recommended allocation factors, along with those proposed by FPL, are provided in Table 1.

Table 1
Proposed and Recommended Allocations of Rate Base Components

Description	FPL Proposed	FIPUG Recommended
Over-Recovery of ECCR Revenues	Total O&M	4CP Demand
Over-Recovery of CPR Revenues	Total O&M	4CP Demand
Storm Maintenance	Gross Plant	T&D Plant
Over-Recovery of Storm Protection Plan Revenues	Total O&M	T&D Plant
ITC Gross-Up Regulatory Liability	Total O&M	Production Plant
Losses from Disposition of Plant	Total O&M	Net Plant
Other Taxes	Total O&M	Net Plant
Deferred Gains for Future Use	Total O&M	PHFFU
Interest on Long-Term Debt	Total O&M	Rate Base
Rate Case Expenses	Total O&M	Total Revenue
Revenue Taxes	Total O&M	Total Revenue

Q PLEASE EXPLAIN WHY YOU ARE RECOMMENDING A 4CP DEMAND ALLOCATOR FOR THE OVER-RECOVERY OF ENERGY CONSERVATION COST RECOVERY AND CAPACITY PAYMENT RECOVERY REVENUES.

A Costs for the Energy Conservation Cost Recovery (ECCR) Clause and Capacity Payment Recovery (CPR) Clause are currently allocated among customer classes using the Twelve Coincident Peak (12CP) + 8% Average Demand (AD) allocation factor, which is the same method used to allocate FPL's production and transmission plant. However, as Mr. Pollock demonstrates, these assets are more appropriately allocated to customers on a 4CP basis. To maintain consistency between the allocation of FPL's production and transmission plant and the ECCR costs, the over-recovered revenues should also be allocated on a 4CP basis.

Q WHY IS IT APPROPRIATE TO ALLOCATE STORM MAINTENANCE COSTS AND THE OVER-RECOVERY OF STORM PROTECTION PLAN COST REVENUES IN PROPORTION TO TRANSMISSION AND DISTRIBUTION PLANT?

A During storms and other severe weather events, energy outages are most frequently the result of damages to a utility's transmission and distribution (T&D) infrastructure. Consequently, costs associated with storm maintenance are incurred to repair these facilities and, therefore, should be allocated in proportion to the underlying assets. Generation assets, as well as general and intangible plant, are not directly impacted by storm damages to the same extent and, therefore, it is not appropriate to include the costs for these assets when developing an allocator to apportion the costs for storm maintenance.

Q IS THE REGULATORY LIABILITY ASSOCIATED WITH GROSSED-UP INVESTMENT TAX CREDITS CAUSED BY O&M EXPENSE AS FPL ASSERTS?

A No. Investment tax credits (ITCs) reduce a utility's tax liability by an amount equal to a percentage of the capital cost of qualifying generating assets. ITCs are unrelated to the O&M of these resources and vary only with the amounts originally invested in the qualifying assets. Therefore, the costs related to these tax credits should be allocated to customer classes in proportion to their share of production plant.

Q PLEASE DISCUSS THE COMPONENTS IN TABLE 1 FOR WHICH YOU RECOMMEND ALLOCATION USING NET PLANT.

A Expenses such as the disposition of utility plant and other (non-income) taxes are more closely related to the value of FPL's net plant than O&M expenses. For example, losses from the disposition of utility plant reflect the differences in value between the amount of the liability for the asset being retired and the amount paid to settle the obligation or retiring the asset.[2] Similarly, FPL's non-income taxes included when calculating test-year expenses are predominantly related to property taxes.[3] Property taxes are levied on the utility's owned assets, including generation, transmission, distribution, general, and intangible plant.

Similarly, the deferred gains for future use should be allocated using the previously allocated plant held for future use.

Q WHY SHOULD INTEREST ON LONG-TERM DEBT BE ALLOCATED ON RATE BASE?

A Interest on long-term debt is a component of the return on rate base that a utility, such as FPL, earns for providing service to its customers. Consequently, allocating this expense on rate base reflects how this amount is calculated and incurred.

Q WHAT COSTS ARE YOU RECOMMENDING BE ALLOCATED BASED ON TOTAL REVENUE?

A I recommend that rate case expenses and revenue taxes be allocated on total revenue. That is, these costs should be allocated to each customer class in proportion to their respective share of the total revenues collected by FPL from all rate classes.

[2] 18 C.F.R. Chapter 1, Part 101 – Uniform System of Accounts, General Instructions No. 25.

[3] FPL Response to FIPUG Interrogatory No. 11, Attachment No. 1 2026 CCOSS, tab: Detailed_COS_ID_Juris_NOI.

Rate case expenses include the costs a utility incurs to participate in rate cases (*e.g.* costs to prepare a filing, outside counsel expenses, travel for appearances). Because, rate case expenses are a general cost of doing business for utilities, allocating these costs on a total revenue basis would reflect that they are incurred to serve all of a utility's customers, regardless of each class's particular usage characteristics.

Revenue taxes are levied as a percentage of the revenues that a utility recovers from its customers. These amounts are directly proportional to the revenues FPL collects from its customers and should be allocated based on total revenues as the direct cost driver.

<u>**Net Operating Income Components**</u>

Q WHAT CHANGES ARE YOU RECOMMENDING TO VARIOUS NET OPERATING INCOME COMPONENTS?

A A summary of my recommended allocation factors for components of the net operating income, along with those proposed by FPL, are provided in Table 2.

Table 2
Proposed and Recommended Allocations
of Net Operating Income Components

Description	FPL Proposed	FIPUG Recommended
Amortization of ITC	Net Plant in Service	Production Plant
Rent from Electric Property	O&M Labor	Plant in Service
Leased Property Depreciation Expense	O&M Labor	Plant in Service
Accretion Expense – Asset Retirement Obligation Regulatory Debit	O&M Labor	Plant in Service
Unbilled Revenues	Sales at Meter	Total Revenues
Regulatory Commission Expenses	O&M Labor	Total Revenues

Q PLEASE EXPLAIN WHY AMORTIZATION OF INVESTMENT TAX CREDITS SHOULD BE ALLOCATED BASED ON PRODUCTION PLANT.

A As previously discussed, ITCs are earned by a utility as a percentage of capital invested in qualifying production plants. Therefore, it is reasonable to allocate costs associated with these tax credits among customer classes based upon these assets specifically, rather than use an allocation based upon all plant types as proposed by FPL.

Q WHAT NET OPERATING INCOME COMPONENTS ARE YOU PROPOSING TO ALLOCATE ON PLANT IN SERVICE?

A I recommend that rent from electric property, depreciation expense for property under capital leases, and accretion expenses for asset retirement obligations be allocated on plant in service. Rent from electric property represents the income that a utility receives for renting out land, facilities, and/or other property owned by the utility to other users of these facilities. Depreciation expense for leased property is incurred based upon the amount of property FPL leases for use in its operations. Accretion expenses are incurred by an electric utility in anticipation of retiring various components of its total electric plant in the future. Because these costs each vary with the amount of FPL's plant, it is reasonable to allocate them on plant in service.

Q PLEASE EXPLAIN WHY UNBILLED REVENUES AND REGULATORY COMMISSION EXPENSES SHOULD BE ALLOCATED ON TOTAL REVENUES.

A Unbilled revenues are revenues a utility earns by providing electric service to customers which are not yet billed to customers. It is inappropriate to allocate such costs on sales at meter, because such an allocation would assume that these revenues are entirely driven by energy use. However, the services a utility provides to customers encompass a variety of functions. Therefore, unbilled revenues should be allocated among customer classes based on base revenues to reflect these various cost drivers for electric service.

Regulatory commission expenses are incurred by utilities through their participation in various proceedings before a regulatory body. As previously discussed in the context of rate case expenses, these expenses are a general cost of doing business for utilities and, therefore, should also be allocated to customers on total revenues to reflect that such expenses are not tied specifically to any particular aspect of the provision of electric service.

Revised CCOSS

Q HAVE YOU PREPARED A CLASS COST-OF-SERVICE STUDY INCORPORATING ALL OF THE CHANGES RECOMMENDED BY MR. POLLOCK AND YOURSELF?

A Yes. FIPUG's revised CCOSS is presented in **Exhibit JL-3**.

3. CILC/CDR INCENTIVE LEVEL

Q WHAT IS THE CILC PROGRAM?

A The CILC program is a non-firm tariff option in which customers agree to curtail load at FPL's direction. The curtailment conditions in the CILC tariff are as follows:

> The Customer's controllable load served under this Rate Schedule is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.[4]

The tariff also defines a generation emergency:

> A Generating Capacity Emergency exists when any one of the electric utilities in the state of Florida has inadequate generating capability, including purchased power, to supply its firm load obligations.[5]

Further, under the Commission's Rules:

> (4) Treatment of Non-Firm Load. If non-firm load (*i.e.,* customers receiving service under load management, interruptible, curtailable, or similar tariffs) is relied upon by a utility when calculating its planned or operating reserves, the utility shall be required to make such reserves available to maintain the firm service requirements of other utilities.[6]

Thus, a CILC customer may be curtailed due to a capacity shortage or emergency anywhere in Peninsular Florida. By allowing FPL to curtail controllable load when resources are needed to maintain system reliability (that is, when there are insufficient resources to meet customer demand), FPL can maintain service to firm (*i.e.*, non-interruptible) customers. For this reason, FPL removes CILC loads in assessing

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[4] FPL Tariff, Commercial/Industrial Load Control Program, Fifth Revised Sheet No. 8.652 (Jan. 1, 2022).

[5] *Id.*, Third Revised Sheet No. 8.659 (Nov. 15, 2002).

[6] 25 Fla. Admin. Code R. 25-6.035.

resource adequacy in its Ten-Year Site Plans. Thus, CILC is a lower quality of service than firm power because it can be interrupted as described above.

Q HOW ARE CILC CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE FPL?

A In exchange for an agreement to curtail load at FPL's control, CILC customers pay a lower base rate than firm customers. Specifically, the Load Control On-Peak Demand charge calculated for the CILC tariffs are reduced by a specific percentage relative to service under a standard rate option to reflect the current value of non-firm capacity.[7] The other applicable demand charges (*i.e.,* Firm On-Peak and Maximum Demand) recover the allocated transmission and distribution demand-related costs and are, thus, similar in concept to FPL's other firm rates.

Q WHAT IS THE CDR PROGRAM?

A Rider CDR is an optional rate available as follows:

> Available to any commercial or industrial customer receiving service under Rate Schedules GSD-1, GSDT-1, GSLD-1, GSLDT-1, GSLD-2, GSLDT-2, GSLD-3, GSLDT-3, or HLFT through the execution of a Commercial/Industrial Demand Reduction Rider Agreement in which the load control provisions of this rider can feasibly be applied.[8]

As with CILC, non-firm load can be curtailed by FPL at any time under a wide range of circumstances. The tariff states:

> <u>Control Condition:</u>
>
> The Customer's controllable load served under this Rider is subject to control when such control alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or

[7] Direct Testimony of Tiffany C. Cohen at 28–29 and Exhibit TCC-6 at 6.

[8] FPL Tariff, Commercial/Industrial Demand Reduction Rider, Twenty-Sixth Revised Sheet No. 8.680 (Feb. 1, 2025).

> projected, would otherwise require the peaking operation of the Company's generators. Peaking operation entails taking base loaded units, cycling units or combustion turbines above the continuous rated output, which may overstress the generators.
>
> <u>Frequency</u>: The Control Conditions will *typically* result in less than fifteen (15) Load Control Periods per year and will not exceed twenty-five (25) Load Control Periods per year. *Typically*, the Company will not initiate a Load Control Period within six (6) hours of a previous Load Control Period.
>
> <u>Notice</u>: The Company will provide one (1) hour's advance notice or more to a Customer prior to controlling the Customer's controllable load. *Typically*, the Company will provide advance notice of four (4) hours or more prior to a Load Control Period.[9] (emphasis added)

Q HOW LONG CAN CURTAILMENT EVENTS UNDER THE CILC AND CDR PROGRAMS LAST?

A A curtailment for CILC and Rider CDR customers will last typically no longer than six hours. Rider CDR specifically states:

> <u>Duration</u>: The duration of a single Load Control Period will *typically* be three (3) hours and will not exceed six (6) hours.
>
> In the event of an emergency, such as a Generating Capacity Emergency (see Definitions) or a major disturbance, greater frequency, less notice, or longer duration than listed above may occur. If such an emergency develops, the Customer will be given 15 minutes' notice. Less than 15 minutes' notice may only be given in the event that failure to do so would result in loss of power to firm service customers or the purchase of emergency power to serve firm service customers. The Customer agrees that the Company will not be liable for any damages or injuries that may occur as a result of providing no notice or less than one (1) hour notice.[10] (emphasis added)

The duration for a CILC customer is typically four (4) hours and will not exceed six (6) hours. The emergency provisions are the same as set forth above for Rider CDR.[11]

[9] *Id.,* Third Revised Sheet No. 8.681 (Jan. 1, 2022).

[10] *Id.*

[11] *Id.*, Fifth Revised Sheet No. 8.652 (Jan. 1, 2022).

During emergency situations, there is no defined limit on how long a curtailment event may last for CILC or Rider CDR customers. In sum, the CILC and CDR programs collectively represent a valuable tool under FPL's control that it can call upon to maintain the reliability of its system.

Q HOW ARE CDR CUSTOMERS COMPENSATED FOR THE CAPACITY THEY PROVIDE FPL?

A Unlike the CILC incentive, which is included as a reduction to the charges under the CILC tariffs, CDR customers receive a $ per kW credit for the amount of load that they agree to reduce when called upon by FPL. Currently, this credit is $8.76 per kW.[12]

Q APPROXIMATELY HOW MUCH NON-FIRM LOAD IS SERVED UNDER THE CILC AND CDR SERVICE OPTIONS?

A The service provided under the CILC and Rider CDR service options account for about 900 MW.[13]

Q ARE THE CILC/CDR SERVICE OPTIONS THE ONLY NON-FIRM RATE OPTIONS OFFERED BY FPL?

A No. FPL provides approximately 1,800 MW of non-firm load. Thus, there are other load management programs besides CILC and CDR.[14]

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[12] *Id.*, Twenty-Sixth Revised Sheet No. 8.680 (Feb. 1, 2025).

[13] Direct Testimony of Andrew W. Whitley at 34.

[14] FPL Response to FRF Interrogatory No. 15.

Q IS FPL PROPOSING ANY CHANGES TO THE CILC/CDR CREDITS IN THIS PROCEEDING?

A Yes. FPL is proposing to reduce the credits paid to these customers by 29%. Specifically, the CDR credit would be reduced 29% from $8.76 per kW to $6.22 per kW.[15] The CILC incentive level would also be reduced proportional to the 29% decrease.[16]

Q ARE THE CILC/CDR PROGRAMS CURRENTLY COST-EFFECTIVE?

A Yes. FPL's analysis reveals that the CILC and CDR programs have a 1.06 times benefit-to-cost ratio using a rate impact measure (RIM) test.[17] Thus, the programs are cost-effective and beneficial for both participants and non-participants.

Q WHY IS FPL PROPOSING TO REDUCE THE PROPOSED CILC AND CDR CREDITS BY 29%?

A FPL states that it targeted a RIM benefit-to-cost ratio of 1.50.[18] After including the impact of administrative costs, the proposed CDR incentive level of $6.22 per kW has a RIM benefit-to-cost ratio of 1.49.[19]

Q WHAT IS THE BASIS FOR FPL'S PROPOSAL TO REDUCE THE INCENTIVES PAID TO CILC AND CDR CUSTOMERS?

A FPL's proposal is based upon analysis sponsored by FPL witness, Mr. Andrew

[15] Direct Testimony of Andrew W. Whitley at 8.

[16] Direct Testimony of Tiffany C. Cohen at 28-29.

[17] Direct Testimony of Andrew W. Whitley, Exhibit AWW-8.

[18] Deposition of Andrew Whitley at 229 (May 7, 2025).

[19] Direct Testimony of Andrew W. Whitley, Exhibit AWW-8.

Whitley, in Exhibit AWW-7 which presents the results of a cost-benefit analysis using the AURORA production cost simulation model. Further, FPL judged that the AURORA-derived benefits from the CILC/CDR programs should exceed the incentives and administrative costs by 50% (*i.e.,* a 1.5 times RIM benefit-to-cost ratio).[20]

Q HOW WAS THE AURORA MODEL USED TO MEASURE THE BENEFITS?

A The AURORA model projected system production costs over the period 2025 through 2071.[21] System production costs include both fixed and variable costs. Fixed costs include the capital costs of future capacity additions and any incremental fixed O&M expenses. Variable costs include system-wide fuel costs and variable O&M expense. Thus, the cumulative present value revenue requirement (CPVRR) net benefit analysis FPL performed includes both fixed and variable costs. FPL calculated the CPVRR net benefits using two AURORA model runs:

1. Assuming the continuation of the CILC and CDR programs (that provide approximately 900 MW of capacity); and
2. Without the CILC and CDR programs.

The difference between the CPVRR net benefits with and without the CILC and CDR programs is meant to measure the long-term benefit of these programs to FPL's customers.

Q DID FPL CONDUCT ANY ANALYSIS SUPPORTING THE TARGETED RIM BENEFIT-TO-COST RATIO OF 1.5?

A No. FPL did not conduct any quantitative analysis that identified the targeted RIM benefit-to-cost ratio of 1.5 as the ideal value to inform the proposed CILC and CDR

[20] Deposition of Andrew Whitley at 231 (May 7, 2025).

[21] Direct Testimony of Andrew W. Whitley at 38.

incentive levels to maximize benefits for both program participants and non-participants. Instead, FPL states that this target was set based on qualitative judgment.[22]

Q DO YOU HAVE ANY CONCERNS WITH FPL'S ANALYSIS OF THE PROJECTED BENEFITS OF THE CILC AND CDR PROGRAMS?

A Yes. In conducting the analysis, FPL made two critical assumptions which reduced the capacity accreditation of (and hence the benefits derived from) the CILC and CDR programs. First, although the state of Florida is a peninsula and, therefore, FPL has electrical connections to neighboring utilities, the FPL system was modeled on a standalone basis as an electrical island. This significantly increased the number of required load control periods. Second, despite the greater need for load control, the present limitations to the frequency, timing, and duration of load control periods were not relaxed.[23]

Q WHY IS IT PROBLEMATIC FOR FPL TO MODEL ITS SYSTEM AS AN ISLAND?

A Modeling its system as an island effectively means that FPL could never rely on the generation and transmission capabilities from neighboring utilities.[24] This is contrary to actual operations in which FPL can rely on electric imports from its neighbors in emergency scenarios. In contrast, the model assumes that FPL would always rely solely on internal resources (*i.e.,* generation and load management) to meet system needs and manage reliability, which explains the increasing frequency of load control

[22] Deposition of Andrew Whitley at 231 (May 7, 2025).

[23] *Id*. at 230–231; Deposition of Arne Olson.

[24] Deposition of Arne Olson.

periods. This is contrary to the Commission's Rules regarding load management and, further, would defeat the purpose of having integrated electric utility systems, including the Florida Reliability Coordinating Council and Southeastern Electric Reliability Council , which allow utilities to provide mutual assistance, particularly when power plants are offline for maintenance. It biases the cost-benefit analysis by assuming that the CILC and CDR programs are deployed in a far more substantive (and unrealistic) manner in the future than in the past. Because these programs were modeled as time-limited resources that could only be deployed for a maximum of six hours, the CILC and CDR programs were assumed to provide a lower percentage of the total program capacity as firm capacity to meet peak demands.[25]

Q IF FPL HAD TO RELY ON ITS OWN INTERNAL RESOURCES TO MEET SYSTEM NEEDS WHILE ALSO MAINTAINING RELIABLE SERVICE, WOULD IT MAKE SENSE TO MAINTAIN THE STATUS QUO WITH RESPECT TO THE LOAD CONTROL PERIODS?

A No. First, as previously stated, under emergency conditions FPL has the option to declare load control periods without constraint. Second, if FPL required additional flexibility to manage the CILC/CDR and other load management programs due to projected diminishing reliability, it would be proposing changes to the load control periods in this proceeding. The fact that FPL is not proposing to revise the load control periods is further evidence that FPL's cost-benefit analysis, and modeling its system as an island, are unreasonable.

[25] *Id.*

Q **BUT FOR THE CONSTRAINTS ON THE FREQUENCY, TIMING, AND DURATION OF TYPICAL LOAD CONTROL PERIODS, WOULD THE CILC/CDR PROGRAMS REMAIN COST-EFFECTIVE?**

A Yes. Without these constraints, the CILC and CDR programs effectively provide 100% of their capacity as firm capacity.[26] Therefore, FPL's modeling assumption that CILC and CDR programs are time-limited resources drastically understates the amount of firm capacity they provide, which drastically understates their value to maintaining system reliability.

Q **SHOULD THE CILC AND CDR INCENTIVES BE REDUCED AS FPL IS PROPOSING?**

A No. FPL's analysis severely understates the benefits of the CILC and CDR programs, and the decision to set the CILC and CDR incentive levels to achieve a RIM benefit-to-cost ratio of 1.50 is arbitrary and not supported by factual robust analysis — or even *any* analysis, Furthermore, reducing the credits paid to these customers at this time would be inconsistent with ongoing trends observed in resource capital costs.

Q **IS THERE ANY DISPUTE THAT THE CILC/CDR PROGRAMS HAVE ALLOWED FPL TO DEFER GENERATION CAPACITY ADDITIONS?**

A No. FPL witness Whitley notes that the benefits of the CILC/CDR programs are related to their ability to defer resource additions.[27] As previously stated, existing service under these programs totals approximately 900 MW. Based on an average installed cost of thermal generation of $657 per kW that FPL has installed since 2000, the total existing CILC/CDR load has deferred approximately $591 million of capacity additions.

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[26] *Id.*

[27] Deposition of Andrew Whitley at 231 (May 7, 2025).

Q DOES FPL ACKNOWLEDGE THAT THE CILC/CDR PROGRAMS WILL CONTINUE TO ALLOW FPL TO DEFER GENERATION CAPACITY ADDITIONS?

A Yes. As acknowledged by FPL witness Whitley, the CILC and CDR programs are cost-effective resources that are capable of deferring resource additions. Specifically, these programs are largely assumed to defer the addition of future battery resources.[28]

Q WHAT IS THE ASSUMED COST OF FPL'S FUTURE BATTERY RESOURCES?

A FPL assumes that battery additions will cost [redacted] per kW in 2027 and decrease over time to $[redacted] per kW in 2034.[29]

Q HOW MANY MEGAWATTS OF BATTERY CAPACITY ARE THE CILC AND CDR PROGRAMS EXPECTED TO DEFER FOR THE PERIOD FROM 2026 TO 2034?

A In the absence of the CILC and CDR programs, FPL projects that it would have to install an additional 100 MW of batteries in 2026, 225 MW in 2033, and 2,384 MW in 2034.[30] In total, the CILC and CDR programs defer 2,709 MW of incremental battery storage additions in the near-term.

Q DOES FPL'S PROPOSAL TO REDUCE THE CILC AND CDR INCENTIVES BY 29% RAISE ANY OTHER CONCERNS?

A Yes. FPL's proposal does not consider the resulting effect of customers potentially switching from non-firm to firm service as a consequence of the reduction in credits.

[28] *Id*. at 231-232.

[29] FPL Response to OPC Request for Production No. 15, CONFIDENTIAL – Whitley.

[30] Direct Testimony of Andrew W. Whitley, Exhibit AWW-7.

Q IS THERE ANY REASON TO BELIEVE THAT CUSTOMERS WOULD CONTINUE THEIR PARTICIPATION IN THE CILC AND CDR PROGRAMS IF THE INCENTIVES ARE REDUCED BY 29%?

A No. Non-firm service is not cost-free. Curtailments can occur at any time when capacity is insufficient throughout Peninsular Florida, not just in FPL's service territory. Thus, CILC and CDR participants have to incur costs to be able to safely curtail load when notified. Reducing the incentive payments by 29% substantially changes the customer's assessment of the risks and benefits of the programs. Under FPL's proposed reduction in incentives participants may convert to firm service if they come to the conclusion that the benefits of remaining on non-firm service are substantially reduced and no longer justify the risks.

Q WHAT WOULD HAPPEN IF ALL THE CILC AND CDR LOAD WERE TO CONVERT FROM NON-FIRM TO FIRM SERVICE?

A FPL would have to install additional capacity to firm up the CILC and CDR loads. Assuming a 20% reserve margin, 900 MW of CILC and CDR non-firm load would require an additional 1,080 MW of capacity.

FPL estimates that the avoided cost of a battery resource is approximately $[redacted] per kW per month.[31] This is approximately [redacted]% higher than the current $8.76 per kW CDR monthly credit. Thus, FPL would incur significant costs to firm up CILC and CDR loads if these customers convert to firm service.

[31] FPL Response to OPC Request for Production No. 15, CONFIDENTIAL – Cohen.

Q HAVE THE CILC AND CDR PROGRAMS PROVIDED (AND EXPECTED TO CONTINUE TO PROVIDE) BENEFITS TO THE GENERAL BODY OF FPL CUSTOMERS?

A Yes. The capacity costs avoided by providing non-firm service under the CILC and CDR Rider rate schedule exceed the incentive payments to these customers. Hence, from a ratemaking perspective, both the CILC and CDR programs are cost-effective.

Q BASED ON YOUR ANALYSIS, IS THERE ANY SUPPORT FOR INCREASING THE CILC AND CDR CREDITS?

A Yes. As previously discussed, FPL's analysis demonstrates that the CILC and CDR programs are cost-effective, even despite the flaws which drastically understate their rated capacity as discussed herein. Thus, increasing the credit for these programs would likely yield a RIM benefit-to-cost ratio that is well above 1.00 and should remain so for at least the term of FPL's proposed four-year rate plan. Based on FPL's estimate of projected battery additions, the cost of avoided capacity is approximately [redacted]% higher than the current CDR monthly credit. Thus, the credit could be increased by up to [redacted]%, or $[redacted] per kW, and still remain cost-effective.

Q WHAT DO YOU RECOMMEND?

A The Commission should reject FPL's proposal to drastically reduce the CILC and CDR credits. FPL's proposal is based upon a flawed analysis which does not fully recognize the capacity benefits provided by the CILC and CDR programs. Instead, the Commission should approve a 40.7% increase, thereby raising the credit from $8.76 to $12.32 per kW for the CDR/CILC programs. The 40.7% reflects the increase in FPL's production plant in service since its last rate case. It also recognizes that these programs have deferred and continue to defer capacity resource additions.

4. CONCLUSION

Q WHAT FINDINGS SHOULD THE COMMISSION MAKE BASED ON THE ISSUES ADDRESSED IN YOUR TESTIMONY?

A The Commission should make the following findings:

- Approve the use of the 4CP allocators as derived in **Exhibit JL-1** to allocate production and transmission demand-related costs.
- Approve the use of the modified 4CP allocators which exclude non-firm load as derived in **Exhibit JL-2** to allocate the cost of interruptible credits.
- Approve FIPUG's revised CCOSS presented in **Exhibit JL-3**.
- Reject FPL's proposal to reduce the CILC/CDR incentive level by 29%.
- Approve a 40.7% increase in the incentive levels of the CILC/CDR programs to $12.32 to recognize each program's capability to defer future capacity resource additions.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

APPENDIX A

Qualifications of Jonathan Ly

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jonathan Ly. My business mailing address is 14323 S. Outer 40 Rd., Town and Country, Missouri 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am an Associate of J. Pollock, Incorporated.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I received a Bachelor of Arts degree in Integrative Biology from the University of California, Berkeley in 2013 and a Master's degree in Energy and Earth Resources from the University of Texas at Austin in 2017. In addition, I have completed a course in utility accounting and finance.

I joined J. Pollock, Incorporated in 2018 as an energy analyst assisting consultants in the preparation of financial and economic studies of investor-owned, cooperative, and municipal utilities on revenue requirements, cost of service and rate design, tariff review and analysis, integrated resource planning, and certificates of convenience and necessity. I began working as an Associate in 2021, expanding upon my responsibilities and assignments in matters I had previously worked on as an energy analyst. I have been involved in various projects in multiple states including Arkansas, Florida, Georgia, Michigan, Minnesota, New Mexico, New York, North Carolina, Texas, and Wyoming.

Q **PLEASE DESCRIBE J. POLLOCK, INCORPORATED.**

A J. Pollock assists clients to procure and manage energy in both regulated and competitive markets. The J. Pollock team also advises clients on energy and regulatory issues. Our clients include commercial, industrial and institutional energy consumers. J. Pollock is a registered broker and Class I aggregator in the State of Texas.

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jonathan Ly

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	24-00270-UT	Stipulation Support	NM	Stipulatino Support regarding ratemaking treatment of solar/battery projects through the FPPCAC; off-system sales margins	5/27/2025
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	25-00027-UT	Direct	NM	Renewable Portfolio Standard Cost Rider	5/21/2025
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	24-00270-UT	Direct	NM	Recovery of Tax Credits, Transfer Costs; Return on Deferred Tax Asset; Off-System Sales Margins	5/5/2025
SOUTHWESTERN ELECTRIC POWER COMPANY	Texas Industrial Energy Consumers	56643	Direct	TX	Impact of Pirkey Retirement; Self-Commitment of Generating Units	1/13/2025
CENTRAL HUDSON GAS & ELECTRIC CORPORATION	Multiple Intervenors	24-E-0461 / 24-G-0462	Rebuttal	NY	Embedded Class Cost-of-Service Studies (Electric/Gas); Electric Rate Design (Customer Charge)	12/18/2024
CENTRAL HUDSON GAS & ELECTRIC CORPORATION	Multiple Intervenors	24-E-0461 / 24-G-0462	Direct	NY	System Control, Load Dispatching, and Other Power Supply; Historic Test-Year; Electric Rate Design (Customer Charge)	11/22/2024
NIAGRA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID	Multiple Intervenors	24-E-0322 / 24-G-0323	Rebuttal	NY	Class Cost-of-Service Study (Electric/Gas); Class Revenue Allocation (Electric/Gas); Rate Design (Customer Charge)	10/18/2024
NIAGRA MOHAWK POWER CORPORATION D/B/A NATIONAL GRID	Multiple Intervenors	24-E-0322 / 24-G-0323	Direct	NY	Class Cost-of-Service Study (Electric/Gas); Class Revenue Allocation (Electric/Gas); Terms and Conditions	9/26/2024
PIEDMONT NATURAL GAS COMPANY, INC	Carolina Utility Customers Association, Inc.	G-9, Sub 837	Direct	NC	Class Cost-of-Service Study; Class Revenue Allocation	8/13/2024
MICHIGAN GAS UTILITIES CORPORATION	Association of Businesses Advocating Tariff Equity	21540	Rebuttal	MI	Class Cost-of-Service Study; Class Revenue Allocation	7/22/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	24-00120-UT	Direct	NM	Transportation Electrification Plan	7/12/2024
SUMMIT UTILITIES ARKANSAS, INC.	Arkansas Gas Consumers, Inc.	23-079-U	Direct	AR	Class Cost-of-Service Study; Class Revenue Allocation	7/10/2024
DUKE ENERGY FLORIDA, LLC	Florida Industrial Power Users Group	20240025-EI	Direct	FL	Solar Projects; Cost-Effectiveness Analysis; Consumer Protections	6/11/2024
TAMPA ELECTRIC COMPANY	Florida Industrial Power Users Group	20240026-EI	Direct	FL	Solar Projects; Cost-Effectiveness Analysis; Consumer Protections	6/6/2024
DUKE ENERGY CAROLINAS, LLC	Carolina Utility Customers Association, Inc.	E-7. SUB 1304	Direct	NC	Fuel and Fuel-Related Cost Factors	5/23/2024

APPENDIX B
Testimony Filed in Regulatory Proceedings
by Jonathan Ly

UTILITY	ON BEHALF OF	DOCKET	TYPE	STATE / PROVINCE	SUBJECT	DATE
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Rebuttal	MI	Uncollectible Expense Allocation; Economic Breakeven Points	5/17/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Stipulation Support	NM	Stipulation Support regarding Long-Term Purchased Power Agreement and Ratemaking Treatment	5/10/2024
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21490	Direct	MI	Class Cost-of-Service Study; Revenue Allocation; Rate Design	4/22/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00384-UT	Direct	NM	Long-Term Purchased Power Agreement; Ratemaking Requests	4/1/2024
LCRA TRANSMISSION SERVICES CORPORATION	Texas Industrial Energy Consumers	55867	Direct	TX	Wholesale Transmsision Rate	3/18/2024
MINNESOTA POWER	Large Power Intervenors	E-015/GR-23-155	Direct	MN	Advanced Metering Infrastructure; Class Revenue Allocation; Rider for Voluntary Renewable Energy	3/18/2024
NATIONAL FUEL GAS DISTRIBUTION CORPORATION	Multiple Intervenors	23-G-0627	Direct	NY	Class Revenue Allocation; Rate Design	3/1/2024
SOUTHWESTERN PUBLIC SERVICE COMPANY	Occidental Permian Ltd.	23-00252-UT	Direct	NM	Certificate of Convenience and Necessity	12/1/2023
EL PASO ELECTRIC COMPANY	Texas Industrial Energy Consumers	54929	Direct	TX	Certificate of Convenience and Necessity	10/24/2023
SOUTHWESTERN PUBLIC SERVICE COMPANY	Texas Industrial Energy Consumers	54634	Direct	TX	Revised Class Cost-of-Service Study; Class Revenue Allocation; Energy Assistance Program	8/4/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Surrebuttal	AR	Additional Sum associated with Power Purchase Agreements	7/20/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	22-082-U	Direct	AR	Additional Sum associated with Power Purchase Agreements	6/8/2023
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Rebuttal	MI	Uncollectible Expense Allocator	5/8/2023
CONSUMERS ENERGY COMPANY	Association of Businesses Advocating Tariff Equity	U-21308	Direct	MI	Class Cost-of-Service Study, Allocation of Other Distribution Plant; Average & Peak Versus Average & Excess Methods	4/17/2023
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Surrebuttal	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	8/1/2022
ENTERGY ARKANSAS, LLC	Arkansas Electric Energy Consumers, Inc.	20-049-U	Direct	AR	Capacity Need and Capacity Value; Risk to Non-Participants; Negative Impacts on Competition; Best Practices	6/22/2022

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Florida Power & Light *Company for Base Rate Increase*	**DOCKET NO. 20250011-EI** ***Filed: June 9, 2025***

AFFIDAVIT OF JONATHAN LY

State of Texas)
) *SS*
County of Harris)

Jonathan Ly, being first duly sworn, on his oath states:

1. My name is Jonathan Ly. I am an Associate of J. Pollock, Incorporated, 14323 S. Outer 40 Rd., Suite 206N, St. Louis, Missouri 63017. We have been retained by Florida *Industrial Power Users Group to testify in this proceeding on its behalf;*

2. Attached hereto and made a part hereof for all purposes is my Direct Testimony and Exhibits, which have been prepared in written form for introduction into evidence in Florida Public Service Commission Docket No. 20250011-EI; and,

3. I hereby swear and affirm that the answers contained in my testimony and the information in my exhibits are true and correct.

Jonathan Ly

Subscribed and sworn to before me this 6 day of June 2025.

Notary Signature

ALYSSA DIANE BENAVIDES
Notary Public, State of Texas
Comm. Expires 01-04-2027
Notary ID 131842666

Alyssa Benavides
(Printed Name), Notary Public

Commission #: 131842666

My Commission expires on 01.04.2027.

FLORIDA POWER & LIGHT COMPANY

Derivation of 4CP Allocation Factors

Line	Rate Class	Jun 2026	Jul 2026	Aug 2026	Sep 2026	4CP Demand	Allocation
		(1)	(2)	(3)	(4)	(5)	(6)
1	**CILC-1D**	346,855	357,044	349,516	330,640	346,014	1.296%
2	**CILC-1G**	15,095	15,173	15,345	14,909	15,130	0.057%
3	**CILC-1T**	177,557	177,839	185,863	181,377	180,659	0.677%
4	**GS(T)-1**	1,842,115	1,905,239	1,921,061	1,828,722	1,874,284	7.021%
5	**GSCU-1**	4,112	4,164	3,949	3,774	4,000	0.015%
6	**GSD(T)-1**	5,498,194	5,574,038	5,576,779	5,262,575	5,477,897	20.521%
7	**GSLD(T)-1**	1,751,493	1,783,926	1,795,354	1,752,159	1,770,733	6.633%
8	**GSLD(T)-2**	617,252	619,802	590,228	595,863	605,786	2.269%
9	**GSLD(T)-3**	126,147	129,656	125,394	137,708	129,726	0.486%
10	**MET**	12,148	11,860	10,766	10,953	11,432	0.043%
11	**OS-2**	1,427	1,403	1,216	987	1,258	0.005%
12	**RS(T)-1**	16,032,917	16,313,104	16,430,315	16,246,162	16,255,624	60.896%
13	**SL/OL-1**	-	-	-	-		0.000%
14	**SL-1M**	879	999	942	1,011	958	0.004%
15	**SL-2**	3,953	4,027	3,955	3,693	3,907	0.015%
16	**SL-2M**	618	618	605	575	604	0.002%
17	**SST-DST**	9	11	5	10	9	0.000%
18	**SST-TST**	22,004	11,560	11,844	18,266	15,919	0.060%
19	**Total Retail**	26,452,776	26,910,464	27,023,138	26,389,383	26,693,940	100.000%

FLORIDA POWER & LIGHT COMPANY
Derivation of Firm Load 4CP Allocation Factors

Line	Rate Class	Firm 4CP Demand	Allocation
		(1)	(2)
1	**CILC-1D**	36,385	0.140%
2	**CILC-1G**	955	0.004%
3	**CILC-1T**	25,120	0.097%
4	**GS(T)-1**	1,874,284	7.202%
5	**GSCU-1**	4,000	0.015%
6	**GSD(T)-1**	5,350,636	20.561%
7	**GSLD(T)-1**	1,744,716	6.705%
8	**GSLD(T)-2**	567,158	2.179%
9	**GSLD(T)-3**	129,726	0.499%
10	**MET**	11,432	0.044%
11	**OS-2**	1,258	0.005%
12	**RS(T)-1**	16,255,624	62.467%
13	**SL/OL-1**		0.000%
14	**SL-1M**	958	0.004%
15	**SL-2**	3,907	0.015%
16	**SL-2M**	604	0.002%
17	**SST-DST**	9	0.000%
18	**SST-TST**	15,919	0.061%
19	**Total Retail**	26,022,691	100.000%

FLORIDA POWER & LIGHT COMPANY
FIPUG's Revised Class Cost-of-Service Study

Line	Description	Total	CILC-1D	CILC-1G	CILC-1T	GS(T)-1	GSCU-1	GSD(T)-1	GSLD(T)-1	GSLD(T)-2	GSLD(T)-3
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**RATE BASE -**										
2	Electric Plant In Service	86,274,360	1,002,266	45,224	378,136	6,001,177	15,561	16,427,227	5,282,938	1,754,693	271,515
3	Accum Depreciation & Amortization	(17,683,082)	(198,830)	(9,038)	(73,036)	(1,259,337)	(3,667)	(3,266,891)	(1,047,343)	(346,882)	(52,186)
4	Net Plant in Service	68,591,278	803,436	36,186	305,099	4,741,840	11,894	13,160,336	4,235,596	1,407,811	219,329
5	Plant Held For Future Use	1,475,168	19,046	834	9,343	103,584	226	301,258	97,715	33,343	6,711
6	Construction Work in Progress	2,012,666	23,648	1,059	9,192	139,569	371	382,266	123,882	41,311	6,547
7	Net Nuclear Fuel	745,109	14,205	574	8,163	49,138	184	170,272	62,731	22,819	5,240
8	Total Utility Plant	72,824,221	860,336	38,653	331,798	5,034,132	12,675	14,014,132	4,519,923	1,505,285	237,828
9	Working Capital - Assets	5,812,779	70,985	3,079	31,479	415,436	1,522	1,053,422	350,746	120,297	21,400
10	Working Capital - Liabilities	(3,507,274)	(42,860)	(1,865)	(18,939)	(249,898)	(869)	(641,285)	(212,725)	(72,709)	(12,924)
11	Working Capital - Net	2,305,505	28,125	1,214	12,539	165,538	652	412,137	138,022	47,588	8,476
12	**Total Rate Base**	75,129,726	888,460	39,867	344,337	5,199,669	13,328	14,426,269	4,657,945	1,552,873	246,304
13	**REVENUES -**										
14	Sales of Electricity	9,617,453	109,379	5,097	47,526	726,872	2,401	1,732,179	548,626	177,559	32,190
15	Other Operating Revenues	267,316	2,109	91	838	18,560	33	35,932	11,134	3,804	924
16	**Total Operating Revenues**	9,884,769	111,488	5,188	48,363	745,432	2,434	1,768,111	559,760	181,363	33,114
17	**EXPENSES -**										
18	Operating & Maintenance Expense	(1,322,364)	(16,207)	(698)	(7,348)	(94,788)	(358)	(236,604)	(79,242)	(27,331)	(4,956)
19	Depreciation Expense	(3,081,922)	(35,570)	(1,606)	(14,254)	(215,673)	(593)	(584,675)	(185,936)	(61,926)	(10,152)
20	Taxes Other Than Income Tax	(903,354)	(10,579)	(476)	(4,037)	(62,563)	(160)	(172,748)	(55,650)	(18,515)	(2,896)
21	Amortization of Property Losses	(15,639)	(191)	(10)	(32)	(834)	7	(4,477)	(1,304)	(389)	(39)
22	Gain or Loss on Sale of Plant	420	5	0		29	0	85	29	9	
23	**Total Operating Expenses**	(5,322,859)	(62,542)	(2,789)	(25,672)	(373,828)	(1,105)	(998,419)	(322,103)	(108,152)	(18,043)
24	**Net Operating Income Before Taxes**	4,561,910	48,946	2,399	22,692	371,604	1,329	769,692	237,657	73,211	15,071
25	Income Taxes	18,213	291	11	158	979	(1)	4,574	1,543	569	117
26	**NOI Before Curtailment Adjustment**	4,580,123	49,236	2,410	22,849	372,583	1,329	774,266	239,200	73,780	15,188
27	Curtailment Credit Revenue	469							329	141	
28	Reassign Curtailment Credit Revenue	(469)	(6)	(0)	(3)	(33)	(0)	(96)	(31)	(11)	(2)
29	Net Curtailment Credit Revenue	(0)	(6)	(0)	(3)	(33)	(0)	(96)	298	130	(2)
30	Net Curtailment NOI Adjustment	(0)	(5)	(0)	(2)	(25)	(0)	(72)	222	97	(2)
31	**Net Operating Income (NOI)**	4,580,123	49,232	2,410	22,847	372,559	1,329	774,194	239,422	73,877	15,186
32	**Rate of Return (ROR)**	6.10%	5.54%	6.05%	6.64%	7.17%	9.97%	5.37%	5.14%	4.76%	6.17%
33	**Parity at Present Rates**	1.000	0.909	0.992	1.088	1.175	1.635	0.880	0.843	0.780	1.011

FLORIDA POWER & LIGHT COMPANY
FIPUG's Revised Class Cost-of-Service Study

Line	Description	MET	OS-2	RS(T)-1	SL/OL-1	SL-1M	SL-2	SL-2M	SST-DST	SST-TST
		(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)
1	**RATE BASE -**									
2	Electric Plant In Service	35,536	24,848	53,319,653	1,650,713	11,267	13,521	3,352	827	35,906
3	Accum Depreciation & Amortization	(7,346)	(4,771)	(11,186,246)	(214,528)	(2,504)	(2,533)	(847)	(204)	(6,893)
4	Net Plant in Service	28,190	20,077	42,133,406	1,436,185	8,763	10,989	2,505	623	29,013
5	Plant Held For Future Use	634	118	900,326	843	86	217	37	3	842
6	Construction Work in Progress	801	529	1,245,918	36,047	268	325	83	15	833
7	Net Nuclear Fuel	385	82	407,592	2,696	217	180	37	0	593
8	Total Utility Plant	30,011	20,806	44,687,243	1,475,771	9,334	11,711	2,662	641	31,281
9	Working Capital - Assets	2,337	1,185	3,664,689	71,060	1,031	1,064	397	42	2,609
10	Working Capital - Liabilities	(1,414)	(724)	(2,202,502)	(45,441)	(600)	(636)	(224)	(25)	(1,631)
11	Working Capital - Net	923	461	1,462,187	25,619	431	427	173	16	978
12	**Total Rate Base**	30,934	21,267	46,149,430	1,501,390	9,765	12,138	2,834	658	32,259
13	**REVENUES -**									
14	Sales of Electricity	4,365	2,029	6,029,038	188,820	1,555	1,850	564	181	7,224
15	Other Operating Revenues	68	36	190,701	2,923	22	43	7	1	89
16	**Total Operating Revenues**	4,432	2,065	6,219,739	191,742	1,577	1,894	571	182	7,313
17	**EXPENSES -**									
18	Operating & Maintenance Expense	(520)	(242)	(838,330)	(14,550)	(244)	(247)	(97)	(8)	(594)
19	Depreciation Expense	(1,286)	(814)	(1,915,323)	(51,766)	(389)	(478)	(128)	(31)	(1,320)
20	Taxes Other Than Income Tax	(371)	(262)	(555,777)	(18,633)	(117)	(146)	(34)	(8)	(382)
21	Amortization of Property Losses	(8)	(9)	(7,608)	(742)	3	(0)	3	(0)	(8)
22	Gain or Loss on Sale of Plant	0	0	260	2	0	0	0	0	
23	**Total Operating Expenses**	(2,185)	(1,327)	(3,316,779)	(85,690)	(748)	(870)	(256)	(48)	(2,304)
24	**Net Operating Income Before Taxes**	2,247	738	2,902,961	106,052	829	1,024	315	134	5,009
25	Income Taxes	6	(1)	10,400	(428)	(2)	1	(1)	(1)	(3)
26	**NOI Before Curtailment Adjustment**	2,254	738	2,913,361	105,624	827	1,025	314	133	5,006
27	Curtailment Credit Revenue									
28	Reassign Curtailment Credit Revenue	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
29	Net Curtailment Credit Revenue	(0)	(0)	(286)		(0)	(0)	(0)	(0)	(0)
30	Net Curtailment NOI Adjustment	(0)	(0)	(213)		(0)	(0)	(0)	(0)	(0)
31	**Net Operating Income (NOI)**	2,253	738	2,913,148	105,624	827	1,025	314	133	5,006
32	**Rate of Return (ROR)**	7.28%	3.47%	6.31%	7.04%	8.47%	8.44%	11.09%	20.29%	15.52%
33	**Parity at Present Rates**	1.195	0.569	1.035	1.154	1.389	1.385	1.819	3.328	2.545