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February 28, 2025

VIA ELECTRONIC FILING
Adam Teitzman, Commission Clerk
Division of Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Docket No. 20250011-EI
Petition by Florida Power & Light Company for Base Rate Increase

Dear Mr. Teitzman:

Attached for filing on behalf of Florida Power & Light Company ("FPL") in the above docket are the direct testimony and exhibits of FPL witness Keith Ferguson.

Please let me know if you have any questions regarding this submission.

Sincerely,

s/ John T. Burnett
John T. Burnett
Vice President & General Counsel
Florida Power & Light Company

(Document 15 of 30)

<u>CERTIFICATE OF SERVICE</u>
Docket 20250011-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic service this 28th day of February 2025 to the following:

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By: *s/ John T. Burnett*
John T. Burnett

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20250011-EI

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KEITH FERGUSON

Filed: February 28, 2025

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Keith Ferguson, and my business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. By whom are you employed and what is your position?

A. I am employed by Florida Power & Light Company ("FPL" or the "Company") as Vice President, Accounting and Controller.

Q. Please describe your duties and responsibilities in that position.

A. I am responsible for financial accounting, as well as internal and external reporting for FPL. This includes ensuring that the Company's financial reporting complies with requirements of Generally Accepted Accounting Principles ("GAAP") and multi-jurisdictional regulatory accounting requirements.

Q. Please describe your educational background and professional experience.

A. I graduated from the University of Florida in 1999 with a Bachelor of Science Degree in Accounting and earned a Master of Accounting degree from the University of Florida in 2000. Beginning in 2000, I was employed by Arthur Andersen in its energy audit practice in Atlanta, Georgia. From 2002 to 2005, I worked for Deloitte & Touche in its national energy practice. From 2005 to 2011, I worked for Mirant Corporation, which was an independent power producer in Atlanta, Georgia. During my tenure there, I held various accounting and management roles and prior to joining FPL in September 2011, I was Mirant's Director of SEC Reporting and Accounting Research. I joined FPL in 2011 as the Assistant Controller and was responsible for overseeing FPL's property and general accounting functions. I have been the Controller of FPL since 2016. I am a Certified Public Accountant ("CPA") licensed in the State of Georgia and a member of the American Institute of CPAs. I am also a member of the Society of Depreciation Professionals and have completed the Society's "Depreciation Fundamentals" training course.

Q. Are you sponsoring or co-sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- Exhibit KF-1 – List of MFRs Sponsored or Co-Sponsored by Keith Ferguson
- Exhibit KF-2 – Impacts to Depreciation Expense using the 2025 Depreciation Study Rates by Year for Base vs. Clause for 2026 and 2027
- Exhibit KF-3 – Summary of Capital Recovery Schedules for 2026 and 2027 – Base Rates vs. Clause
- Exhibit KF-4 – Proposed Dismantlement Company Adjustments for Base vs. Clause
- Exhibit KF-6 – 2025 Cost Allocation Manual
- Exhibit KF-7 – Affiliate Charges Based on Billing Methodology for the 2026 Projected Test Year

I am co-sponsoring the following exhibits:

- Exhibit NWA-2 – 2025 Dismantlement Study, filed with the direct testimony of FPL witness Allis
- Exhibit KF-5 – SPPCRC Cost of Removal and Retirements

Q. Are you sponsoring or co-sponsoring any Minimum Filing Requirements in this case?

A. Yes. Exhibit KF-1 lists the minimum filing requirements ("MFRs") that I am sponsoring and co-sponsoring.

Q. What is the purpose of your testimony?

A. My testimony covers five topics that serve as inputs to the Company's calculation of revenue requirements:

- I provide an overview of the results of FPL's depreciation study (the "2025 Depreciation Study"), which was conducted in accordance with the rules and requirements of the Commission, and the related Company adjustment. The 2025 Depreciation Study has been prepared by FPL witness Allis of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") and is supported in his direct testimony in this docket.
- I support the request for recovery of retired assets with unrecovered balances through capital recovery schedules.
- I present and provide an overview of the Company adjustment as a result of FPL's dismantlement study (the "2025 Dismantlement Study"), which was conducted in accordance with the rules and requirements of the Commission. The 2025 Dismantlement Study has been prepared by FPL witness Allis and is supported in his direct testimony.

- I provide an overview of the Company adjustment to move retirements and cost of removal associated with projects recovered through FPL's Storm Protection Plan Cost Recovery Clause ("SPPCRC") from base to clause.
- I provide testimony and information on various affiliate issues.

Q. Please summarize your testimony.

A. The 2025 Depreciation Study reflects a modest increase in the 2026 and 2027 depreciation accruals primarily as a result of continued investments in FPL's system and an increase in removal costs for certain assets in the distribution function since depreciation rates were approved in FPL's 2021 Rate Settlement.[1]

FPL has retired or plans to retire certain assets that are not yet fully depreciated. Consistent with Rule 25-6.0436, Florida Administrative Code ("F.A.C."), and Commission practice, FPL is proposing capital recovery schedules that seek to recover the remaining investment for those specific assets over a 10-year period.

FPL, as required by the Commission's rules, has established and maintained a dismantlement reserve for its non-nuclear generating units and related battery storage. In accordance with Rule 25-6.0436, F.A.C., FPL has updated its cost estimates and revised its annual accrual accordingly. The increase in the revised annual accrual primarily reflects new solar plants and battery storage assets that have been or will be

[1] Stipulation and Settlement Agreement approved in FPL's 2021 Rate Case in Docket No. 20210015-EI, Commission Order Nos. PSC-2021-0446-S-EI and PSC 2021-0446A-S-EI.

constructed since the 2021 Dismantlement Study was prepared and filed in FPL's 2021 Rate Case in Docket No. 20210015-EI.

In addition, I recommend removing retirements and cost of removal associated with projects recovered through FPL's SPPCRC from FPL's base rates beginning on January 1, 2026.

The impacts from the above items are included as Company adjustments in FPL's 2026 Projected Test Year and 2027 Projected Test Year.

Finally, I address FPL's practices for the provision of shared corporate services to the NextEra Energy, Inc. ("NEE") enterprise, including regulated and unregulated affiliates. The long-standing cost charging methods approved by this Commission and by the Federal Energy Regulatory Commission ("FERC") facilitate FPL's provision of these corporate services at lower costs to FPL's customers while ensuring no subsidization of affiliate activities. Those practices are unchanged since FPL's 2021 Rate Case and remain fully consistent with Commission requirements.

II. 2025 DEPRECIATION STUDY

Q. Please summarize the impact of the 2025 Depreciation Study on FPL's 2026 Projected Test Year and 2027 Projected Test Year.

A. Since its last depreciation study in 2021, FPL has worked closely with its depreciation consultant, Gannett Fleming, to incorporate updated technical data into the 2025 Depreciation Study. FPL witness Allis of Gannett Fleming presents the results of the

2025 Depreciation Study. The 2025 Depreciation Study reflects a modest increase in depreciation accruals primarily resulting from FPL's continued investments and increases in removal costs most notably for the distribution function.

The total increase in depreciation expense for the 2026 Projected Test Year as a result of the 2025 Depreciation Study is $180.4 million, which includes a $135.5 million increase related to base rate assets and a $44.9 million increase related to cost recovery clauses. The $135.5 million increase related to base rate assets is primarily a result of the following:

- $96.9 million increase in the distribution function resulting from an increase in depreciation rates from FPL's 2021 Rate Settlement and mostly driven by continued investments and increases in removal costs;
- $15.1 million increase in the nuclear function as a result of continued investments; and
- $13.5 million increase in the steam function as a result of an adjustment in the estimated retirement date for Scherer Unit 3 from 2047 to 2035 based on the date disclosed in Georgia Power's 2025 Integrated Resource Plan.[2]

For the 2027 Projected Test Year, there is an increase of $190.3 million in depreciation expense as a result of the 2025 Depreciation Study, of which $141.8 million relates to base rate assets and $48.5 million relates to cost recovery clauses. The same primary drivers for the 2026 Projected Test Year apply to the $141.8 million increase related to base rate assets in the 2027 Projected Test Year with a $99.8 million increase in the

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[2] https://www.georgiapower.com/about/company/filings/irp.html

distribution function, $15.8 million increase in the nuclear function, and $13.0 million in the steam function. FPL witness Allis explains in more detail the underlying drivers for the changes in the depreciation rates that resulted in the changes in expense noted above.

Q. What is the basis for the plant and reserve balances used in FPL's 2025 Depreciation Study?

A. The parameters used in the 2025 Depreciation Study are based in part on the statistical analyses of actual plant and reserve balance activity through December 31, 2023, which incorporates data through the most recent full year of historical data (*e.g.*, retirements, net salvage, and etc.) that was available at the time the study was prepared. The results of these parameter analyses are then applied to the forecasted gross plant balances through the end of 2024, which includes actual balances as of September 30, 2024, to determine the appropriate depreciation rates. As FPL is using forecasted balances as of December 31, 2025, for the 2025 Depreciation Study, FPL appropriately included new assets that are not yet in service, such as new solar and battery storage facilities, that are expected to be in service by the end of 2025.

Q. Has the Company calculated the impact to depreciation expense in the 2026 Projected Test Year and 2027 Projected Test Year using the proposed depreciation rates from the 2025 Depreciation Study?

A. Yes. The depreciation Company adjustment reflects the impact of the difference in the application of the rates resulting from the 2025 Depreciation Study as compared to the currently approved depreciation rates. The current depreciation rates approved in FPL's 2021 Rate Settlement were used to prepare the forecast for the 2026 Projected

Test Year and 2027 Projected Test Year. Accordingly, FPL has calculated the impact to the 2026 Projected Test Year and 2027 Projected Test Year to reflect changes in base depreciation expense and accumulated depreciation based on the resulting depreciation rates in the 2025 Depreciation Study, which are included in the calculation of revenue requirements sponsored by FPL witness Fuentes and reflected on MFRs B-2 and C-3 for both the 2026 Projected Test Year and 2027 Projected Test Year. The reconciliation of total Company depreciation expense included in FPL's 2026 Projected Test Year and 2027 Projected Test Year forecasts to the calculated expense based on the 2025 Depreciation Study are reflected on Exhibit KF-2.

Q. Is the entire impact to depreciation expense associated with base rate investments? Please explain.

A. No. Because some of FPL's investments are recovered through FPL's Environmental Cost Recovery Clause ("ECRC"), Energy Conservation Cost Recovery Clause, Capacity Cost Recovery Clause, and SPPCRC, the impact to base rate revenue requirements for the 2026 Projected Test Year and 2027 Projected Test Year must exclude the amount of depreciation related to clause-recoverable investments and include only the depreciation for investments recovered through base rates. Exhibit KF-2 reflects the total depreciation expense increase using the 2025 Depreciation Study rates and delineates between base rates and clause recovery. With respect to FPL's clause filings, FPL will apply the new depreciation rates approved in this proceeding to all clause-recoverable investments beginning on January 1, 2026, which is the date when the approved depreciation rates are to become effective, and will reflect these new depreciation rates in the next applicable clause filings.

Q. Are there any other items related to FPL's 2025 Depreciation Study that you wish to elaborate on?

A. Yes. As discussed in testimonies of FPL witnesses Laney and Fuentes, FPL began complying with FERC Order 898 on January 1, 2025. As a result, FPL integrated the new prescribed functions and subaccounts for solar, battery storage, and other renewables as well as computer hardware, software, and communication equipment into its accounting structure. Therefore, the plant-in-service and accumulated depreciation reserve balances for the accounts used prior to FERC Order 898 have been reclassified into these new FERC accounts. Generally, the recommended depreciation or amortization periods are consistent with those previously adopted by the Commission for similar assets in accounts or subaccounts used prior to FERC Order 898.

III. CAPITAL RECOVERY SCHEDULES

Q. Please describe the capital recovery schedules for assets that have been retired or will be retired but are not fully depreciated.

A. As shown on Exhibit KF-3 and pursuant to Rule 25-6.0436, F.A.C., FPL has reflected its proposed capital recovery schedules for assets that have been retired or will be retired but are not fully depreciated, which FPL is requesting to be recovered over a 10-year period. FPL is requesting recovery of the following unrecovered investments either through base rates or clause recovery.

- <u>500 kV Transmission Rebuild Project (Years 2024 and 2025)</u>: In the 2021 Rate Settlement, the Commission approved the establishment of a regulatory asset for the estimated remaining unrecovered investment and Cost of Removal ("COR") for retirements associated with the replacement of FPL's 500 kV transmission system during years 2023 and 2024. The commencement of amortization in the subsequent year, 2024 and 2025, respectively, was approved using the depreciation rates for transmission assets based on the depreciation rates approved in FPL's 2021 Rate Settlement. As FPL explained in the 2021 Rate Case, the amortization of the remaining unrecovered regulatory asset balance is to be addressed in the Company's next general base rate proceeding, which is the instant case. Consistent with that obligation, FPL is herein requesting the recovery of the estimated remaining base rate unrecovered regulatory asset balance pertaining to retirements of FPL's 500 kV Transmission System ($33.1 million for Year 2024 and $25.4 million for Year 2025) as of December 31, 2025, to be amortized over a 10-year period;

- <u>500 kV Transmission Rebuild Project (Years 2026 and 2027)</u>: FPL's 500 kV Transmission System continues to be retired as work is performed and the remaining unrecovered investment will be transferred to a regulatory asset in tranches on an annual basis, similar to what was approved by the Commission in FPL's 2021 Rate Settlement. Therefore, FPL estimates $10.0 million of remaining base rate unrecovered investment and related COR to begin amortization in January 2026 and $3.5 million beginning in January 2027. The amount shown for year 2026 amortization relates to the remaining unrecovered investment and COR expected as a result of retirements through 2025 and the year 2027 amortization relates to COR as a result of retirements occurring in 2026;

- Plant Daniel Units 1 and 2: In the 2021 Rate Settlement, the Commission approved the Company's request to reflect the early retired investment associated with Plant Daniel Units 1 and 2 as a negative amount (debit) in FPL's accumulated depreciation reserve for the respective plant accounts and continue the depreciation for these retirements using depreciation rates as approved in the former Gulf Power Company's 2017 Rate Settlement.[3] The establishment and amortization of the regulatory asset for the unrecovered balance was to be addressed in the Company's next base rate proceeding, which is this proceeding. FPL is requesting the recovery of $427.4 million ($120.4 million related to base rate investments and $307.0 million related to cost recovery clauses) of the remaining early retired investment associated with Plant Daniel Units 1 and 2 as of December 31, 2025, to be amortized over a 10-year period; and

- Customer Information System ("CIS") and Integrated Systems: As discussed in greater detail by FPL witness Nichols, FPL plans to replace its existing CIS and integrated systems with a new customer service platform. FPL is requesting the recovery of $44.7 million of the estimated unrecovered remaining base rate investment related to the existing CIS and integrated systems as of December 31, 2026, to be amortized over a 10-year period beginning January 1, 2027.

[3] Stipulation and Settlement approved in Gulf Power Company's 2017 Rate Case in Docket No. 20160186-EI, Order No. PSC-17-0178-S-EI issued May 16, 2017.

Q. Is the Company retiring other significant capital assets outside its 2026 Projected Test Year and 2027 Projected Test Year? If so, please explain.

A. Yes. In 2027, FPL expects to retire $19.9 million of estimated remaining investment and COR related to FPL's 500 kV Transmission System assets with amortization beginning in January 2028. Once the retirements of the 2028 tranche of assets take place, the Company proposes to establish a regulatory asset for the estimated remaining investment and COR and commence its amortization through base rates in January 2028 using the depreciation rates for the transmission assets approved by the Commission in this proceeding. During its next base rate case, the Company will address amortization of the remaining unrecovered regulatory asset balance.

Q. Are the capital recovery schedules delineated between base rates and clause recovery? If so, please explain.

A. Yes. Exhibit KF-3 illustrates the capital recovery schedule totals by year and by recovery mechanism. The proposed recovery amounts for clause assets are not included in this base rate request and, instead, will be reflected in the applicable clause filings depending on the retirement date. As reflected in Exhibit KF-3, the resulting Company adjustment related to base rates for the 2026 Projected Test Year and 2027 Projected Test Year are $7.2 million and $12.0 million, respectively, and are included in the calculation of revenue requirements sponsored by FPL witness Fuentes and reflected on MFRs B-2 and C-3 for both the 2026 Projected Test Year and 2027 Projected Test Year.

IV. 2025 DISMANTLEMENT STUDY

Q. Please provide an overview of the approach FPL used for the preparation of its 2025 Dismantlement Study.

A. FPL engaged Gannett Fleming to perform the 2025 Dismantlement Study. As part of the Dismantlement Study, Gannett Fleming conducted a detailed review of the fossil, solar, and battery storage assets in FPL's fleet in order to get a more precise view of the current cost of dismantling those facilities.

Since the 2021 Dismantlement Study was filed in the 2021 Rate Case, the Company has performed dismantlement activities at several generating units, including closure activities required in accordance with the Coal Combustion Residuals Rule. FPL also added or plans to add new solar and battery storage facilities to the generation fleet as further explained by FPL witness Whitley. The 2025 Dismantlement Study is addressed in FPL witness Allis' testimony and Exhibit NWA-2, which I co-sponsor.

Q. Please describe the process used to determine the dismantlement cost estimates in the 2025 Dismantlement Study.

A. As discussed further by FPL witness Allis, Gannett Fleming obtained and reviewed plant-specific engineering drawings, performed numerous plant site visits, and interviewed Company personnel. Based on this information and their professional experience, Gannett Fleming developed labor and materials and equipment costs for each major dismantlement activity. Gannett Fleming estimated the salvage value of the materials that would be left at each site after completion of the dismantlement activities. The resulting dismantlement cost estimates developed by Gannett Fleming represent "the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service" in accordance with Rule 25-6.04364, F.A.C.

In addition to the existing sites, Gannett Fleming also developed estimates for solar and battery storage facilities that will be used as a proxy estimate for generating units that will commence commercial operation during years 2025 through 2029. This is consistent with the approach that FPL employed in its 2016 and 2021 Dismantlement Studies.

Q. In addition to the dismantlement costs reflected in the 2025 Dismantlement Study, did the Company consider other factors in the calculation of the dismantlement accrual?

A. Yes. As previously noted, the Company has commenced or continued dismantlement activities at several generating units. The Company has incorporated in the calculation of the dismantlement accrual its internal forecasts for the remaining dismantlement costs at each site to be incurred.

Q. What escalation rates did FPL use in preparing the 2025 Dismantlement Study accrual calculations?

A. FPL utilized the September 2024 Global Insight escalation rates, which was the most recent vintage available at the time the study was undertaken, in developing the 2025 Dismantlement Study accrual calculations.

Q. Please describe the results of the 2025 Dismantlement Study and related accruals.

A. The 2025 Dismantlement Study calculated a current total cost of dismantlement of $2,284 million (expressed in 2025 dollars), including FPL's internal forecast estimates for dismantlement activities as reflected in Section 5.1 of Exhibit NWA-2. The resulting annual dismantlement accrual is $106.4 million, of which $96.2 million relates to base rate assets. This is a net increase of approximately $58.7 million ($59.6 million increase for the base rate portion), over the current annual accrual from the 2021 Rate Settlement included in FPL's 2026 Projected Test Year and 2027 Projected Test Year. Of the total $58.7 million increase in the dismantlement accrual, approximately $46 million is related to new solar plants and battery storage assets that have been or will be constructed since the 2021 Dismantlement Study was prepared, as reflected in Section 2 of Exhibit NWA-2.

Q. What steps did FPL take to minimize the increase in the dismantlement accrual?

A. The dismantlement study is fundamentally an aggregation of the forecasted cost of dismantling all of FPL's non-nuclear generating units and battery storage assets. The resulting annual accrual is a function of the present value of estimated future cost to dismantle each of those units or assets as compared to its forecasted reserve as of December 31, 2025. At any point in time, the reserve position of any specific unit or asset will vary based on the forecasted reserve relative to the theoretical reserve, which takes into account the remaining life over which the estimated future costs are expected to be accrued. Some units or assets will have excess reserves while others will be in a deficit position.

As reflected on Exhibit KF-4, FPL has proposed transfers of reserve balances from the units or assets that either had excess reserves or were the furthest from retirement to the units or assets that are closest to retirement or assets with dismantlement activities in progress. In doing so, FPL minimized the calculated incremental dismantlement accrual. As a result, FPL is proposing to transfer approximately $86.3 million of dismantlement reserve between the steam, other production, solar, battery storage, and other renewable production functions, and $12.5 million of dismantlement reserve between base and clause recoverable assets. The proposed transfers related to base rates are included as part of the dismantlement Company adjustment reflected on MFR B-2 for both the 2026 Projected Test Year and 2027 Projected Test Year.

Q. Is FPL proposing a Company adjustment to reflect the impact of the annual accruals from the 2025 Dismantlement Study on its 2026 Projected Test Year and 2027 Projected Test Year?

A. Yes. As with depreciation, FPL used the current Commission approved dismantlement accrual from its 2021 Rate Settlement to prepare its 2026 Projected Test Year and 2027 Projected Test Year forecasts and is proposing a Company adjustment to reflect the updated accrual contained in the 2025 Dismantlement Study. Similar to the depreciation study results, the Company adjustment for the change in dismantlement accrual must be bifurcated between base and clause recovery. Exhibit KF-4 provides an overview of the split between base and clause recovery for purposes of determining the Company adjustment for base rates for 2026 and 2027. The resulting Company adjustments related to base rates are included in the calculation of revenue requirements sponsored by FPL witness Fuentes and reflected on MFRs B-2 and C-3 for both the 2026 Projected Test Year and 2027 Projected Test Year.

V. SPPCRC COST OF REMOVAL AND RETIREMENTS

Q. Please summarize the existing recovery method for COR and retirements associated with SPP projects.

A. For Transmission and Distribution assets, FPL's asset accounting system books the associated COR and retirements based on the vintage of the assets being retired consistent with standard utility practice. In addition, FPL's asset accounting system automatically records COR and retirements for capital replacement projects based on the related cost recovery mechanism, including those recovered through FPL's SPPCRC. However, pursuant to the Settlement approved by Commission Order No. PSC-2020-0293-AS-EI in Docket No. 20200092-EI, FPL currently recovers the COR and retirements related to SPP projects through base rates. In order to do so, FPL must manually record an adjustment to move these capital costs from SPPCRC to base.

Q. Is FPL proposing a Company adjustment for the recovery of COR and retirements associated with SPP projects?

A. Yes. In order to align cost recovery of all capital costs associated with SPP projects, FPL proposes a Company adjustment as shown on Exhibit KF-5 to move the recovery of COR and retirements associated with SPP projects from base rates to the SPPCRC starting on January 1, 2026. This change, if approved in this proceeding, will be implemented in the next applicable SPPCRC filing. The resulting Company adjustments to base rates are included in the calculation of revenue requirements sponsored by FPL witness Fuentes and reflected on MFR B-2 for both the 2026 Projected Test Year and 2027 Projected Test Year.

VI. CORPORATE SERVICES AND AFFILIATE TRANSACTIONS

Q. Please describe the NEE corporate and fleet services organizational model, FPL's role in that model, and its benefits.

A. In the years both before and since the formation of NEE, FPL has remained the primary NEE subsidiary, and consistently performs the required corporate center activities for all affiliated entities.

As the functioning corporate center for NEE, FPL incurs costs in order to perform necessary shared fleet operating and corporate support functions, with the ultimate goal to efficiently and cost-effectively lever talent and resources across the enterprise, which is beneficial to FPL and its customers. Exhibit KF-6 contains FPL's 2025 Cost Allocation Manual ("CAM"), which lists the corporate support functions and the fleet services activities provided by FPL across the broader NEE operating businesses.

While the shared corporate service activities embedded in FPL today continue to be necessary to support the provision of electric service to FPL's retail customers, charging a portion of these support services to its affiliates has allowed FPL to reduce its share of these necessary fixed costs for the benefit of its retail customers. This structure has proven over the years to be efficient and effective from an operating perspective. The special skills and talents of FPL's employees and contractor resources are consistently leveraged over the largest organizational reach.

Q. Have there been any material changes in affiliate transaction processes or controls since FPL's 2021 Rate Case?

A. No. FPL's current affiliate transaction processes and controls have been in place since at least 2003 and have remained unchanged since the 2021 Rate Case. Continuing the existing shared services structure ensures proper control of shared and centralized administrative functions, including compliance with all applicable regulatory rules and regulations. This centralization enables FPL to draw on the talent and expertise of the entire organization, which has resulted in increased efficiencies and reduced costs to FPL.

Q. Have there been any changes in the accounting for affiliate transactions since FPL's 2021 Rate Case?

A. Yes. FPL has refined the accounting for credits to FPL related to the Corporate Services Charge ("CSC") and the labor overheads associated with affiliate direct charges. Prior to 2024, the credits were recorded to FERC account 922 Administrative expenses transferred – Credit, so that they effectively offset the expenses posted to various originating administrative and general ("A&G") FERC accounts. Beginning in 2024, FPL credits the originating FERC accounts for all CSC and affiliate direct charge overhead activity to more precisely reflect the balances in each of the A&G FERC accounts. In addition, FPL now records amounts charged to affiliates for their allocated share of depreciation expense and return on investment associated with shared enterprise assets to FERC account 456 Other electric revenues instead of crediting FERC account 922.

Q. Are FPL's affiliate billing practices codified?

A. Yes. FPL uses an integrated structure of billings and allocations that are codified in the CAM. Maintaining the CAM is a requirement under Rule 25-6.1351, F.A.C. ("Affiliate Rule"). In addition, FPL's CAM largely follows the published guidelines recommended by the National Association of Regulatory Utility Commissioners ("NARUC") and is consistent with our approach over at least the last 10 years, including three prior base rate reviews, with no material process changes. FPL's CAM details the types of services provided to affiliates, along with explanations of the billing methodologies. FPL's 2025 CAM is included as Exhibit KF-6.

Q. Have there been any changes to the billing methodologies for charging FPL costs to its affiliates since the 2021 Rate Case?

A. No. FPL's current billing methodologies for costs charged to its affiliates have been in place since at least 2003 and remain unchanged since the 2021 Rate Case. FPL continues to use three methods to charge costs of shared activities to its affiliates. These methods are commonly employed by other utilities and are recommended by the FERC and the NARUC:

1. <u>Direct Charges</u> – Costs of resources used exclusively to provide services for the benefit of one company and are directly charged to that entity. FPL fully loads all direct charges to affiliates and uses this methodology whenever possible and practical. Activity billed using the direct charge methodology is not recorded on FPL books and records and, instead, is charged on the books and records of the benefitting entity. Therefore, direct charges are not included in FPL's cost of service.

2. Operations Support Charges – Operations Support Charges are used by FPL to allocate support costs for NEE's Nuclear fleet support operations, which provide services to both the FPL and NextEra Energy Resources, LLC ("NEER") fleet of nuclear units. This allocation is based on each entity's number of operating units, with a current split of 57% to FPL and 43% to NEER. These charges are based on actual costs for the enterprise support activity and are billed using the direct charge methodology; therefore, Operations Support Charges are not included in FPL's cost of service.

3. CSC – A significant portion of corporate support services that benefit both FPL and its affiliates are billed through the CSC, which is further defined by the two distinct allocation methods below. Activity billed to affiliates via the CSC is reflected in FPL's books and records as a credit to either revenue or expense and, therefore, reduces FPL's cost of service.

    a. Specific Driver – The allocation of costs of ongoing services shared jointly to support utility and affiliate operations that have distinct cost drivers. These drivers or factors have a direct relationship to the causation of the expense and the effect this activity has on the operations of the benefiting entity. See Exhibit KF-6 for examples of the cost pools that are allocated using specific drivers.

    b. Massachusetts Formula – The costs of corporate governance and strategic activities shared jointly to support utility and affiliate operations that do not have distinct cost drivers are allocated using the Massachusetts Formula, a methodology widely accepted by utility regulators as a fair and reasonable way to allocate common costs among affiliates. The Massachusetts Formula has three components: (1) property, plant and equipment, (2) revenue, and (3) payroll. The annual amounts forecasted for each of these components are used as the basis in calculating the percentage to be charged to each affiliate. Averaging the percentages for property, plant and equipment, revenues, and payroll has proven to be a reasonable means of allocating corporate governance and general support services.

Continuing these existing billing methodologies will ensure that all shared services are properly charged to the benefiting entities in the NEE organization.

Q. What percent of affiliate support provided by FPL will be billed using either the direct charge methodology or specific drivers?

A. As shown on Exhibit KF-7, approximately 73% of the support FPL forecasts it will provide to its affiliates in the 2026 Projected Test Year will be billed using the direct charge method or allocated in the CSC using specific drivers. This is made up of approximately 33% using the direct charge methodology, 36% using specific drivers, and 4% related to the Nuclear Operations Support Charge. FPL forecasts similar billing levels for affiliate support for the 2027 Projected Test Year.

Q. What is the amount of CSC forecasted for the 2026 Projected Test Year and 2027 Projected Test Year?

A. FPL forecasts the CSC to affiliates to be approximately $154 million and $171 million in the 2026 Projected Test Year and 2027 Projected Test Year, respectively. These amounts are reflected as a credit to the originating administrative and general expense accounts or other operating revenue, in the calculation of revenue requirements in each of these years.

Q. Are most of the costs included in the CSC allocated using activity-specific drivers?

A. Yes. For the 2026 Projected Test Year, 57% of the CSC cost pool is expected to be allocated using specific drivers and 43% using the Massachusetts Formula. For the 2027 Projected Test Year, 58% of the CSC cost pool is expected to be allocated using specific drivers and 42% using the Massachusetts Formula. FPL makes a significant effort to identify causal relationships between costs and the activities that drive them in order to achieve a more precise distribution of shared costs among FPL and its affiliates.

Q. Please describe the integrated controls that FPL designs, maintains, and relies on to ensure that FPL retail customers do not subsidize the operation of an affiliate.

A. The Regulatory Accounting group within FPL is responsible for ensuring compliance with the Affiliate Rule. This group, in collaboration with the Legal and Compliance teams, is the primary control and oversight organization, whose mission is to ensure that FPL complies with affiliate transaction requirements. They monitor the affiliate billing process and work with all business units across the enterprise to ensure that each complies with the Affiliate Rule and properly charges or allocates costs as required. They also work closely with all centralized shared services teams, periodically reviewing all cost distributions to ensure charges are appropriate and that unregulated activities are not subsidized by regulated customers.

FPL has codified the required practices and procedures that each employee must adhere to in the conduct of corporate shared services and appropriate billings in the CAM, following the guidelines recommended by the NARUC. The CAM is updated annually by the FPL Regulatory Accounting group and can be readily accessed by each and every employee through the internal NEE corporate website.

The Company's Sarbanes-Oxley narratives provide FPL's required affiliate transaction controls. These narratives are reviewed on a quarterly basis and attested to by FPL management. In addition, other processes ensure proper control over affiliate allocation. For example, bi-weekly payroll reviews by each employee's supervisor are conducted to ensure that any payroll incurred in support of an affiliate is appropriately charged to that affiliate, and asset transfer requirements detail market testing procedures for sales between FPL and affiliates to ensure Affiliate Rule compliance.

Q. Does the Company perform internal reviews of its affiliate processes?

A. Yes. The Company periodically reviews its affiliate processes. Most recently, during 2024, the Internal Audit department performed a review of the processes and procedures employed by the FPL Regulatory Accounting group related to the CSC, Operations Support Charges, and direct charges. The report contained no findings of non-compliance with the Affiliate Rule. The controls in place were determined to be effective, and the policies and procedures around affiliate transactions were consistently applied throughout the Company. Additionally, FPL's Regulatory Accounting and Finance departments undertake periodic reviews of the affiliate costs as part of the budget cycle process.

Q. Is FPL subject to reporting requirements by the Commission with respect to its affiliate transactions?

A. Yes. FPL complies with affiliate accounting and reporting requirements mandated by this Commission. That reporting includes the required annual filing of the Diversification Report, which includes details of transactions with affiliates and changes in affiliate commercial contracts with FPL. The most recent Diversification Report available for FPL is provided in MFR C-31.

Q. Are affiliate costs subsidized by FPL customers?

A. No. To the contrary, FPL will continue to accomplish two important objectives for its customers with respect to corporate support and affiliate charges. First, the Company will continue to ensure that it complies with all regulatory requirements ensuring that FPL customers do not subsidize affiliates. Second, FPL will continue to lever the robust, highly specialized, commercial, and technical talents of the broader business teams that it has amassed across the NEE enterprise in performing these corporate and fleet services, which enable far greater benefits than FPL could ever deliver to customers as a standalone business.

Q. Does this conclude your direct testimony?

A. Yes.

Florida Power & Light Company

MFRs SPONSORED OR CO-SPONSORED BY KEITH FERGUSON

MFR	Period	Title
SOLE SPONSOR:		
B-25	2026 Projected Test Year 2027 Projected Test Year	ACCOUNTING POLICY CHANGES AFFECTING RATE BASE
C-30	2026 Projected Test Year 2027 Projected Test Year	TRANSACTIONS WITH AFFILIATED COMPANIES
C-31	2026 Projected Test Year 2027 Projected Test Year	AFFILIATED COMPANY RELATIONSHIPS
C-32	2026 Projected Test Year 2027 Projected Test Year	NON-UTILITY OPERATIONS UTILIZING UTILITY ASSETS
F-01	2024 Historic Year 2027 Projected Test Year	ANNUAL AND QUARTERLY REPORTS TO SHAREHOLDERS
F-02	2024 Historic Year 2027 Projected Test Year	SEC REPORTS
CO-SPONSOR:		
B-02	2026 Projected Test Year 2027 Projected Test Year	RATE BASE ADJUSTMENTS
B-11	2026 Projected Test Year 2027 Projected Test Year	CAPITAL ADDITIONS AND RETIREMENTS
C-02	2026 Projected Test Year 2027 Projected Test Year	NET OPERATING INCOME ADJUSTMENTS
C-03	2026 Projected Test Year 2027 Projected Test Year	JURISDICTIONAL NET OPERATING INCOME ADJUSTMENTS
C-08	2027 Projected Test Year	DETAIL OF CHANGES IN EXPENSES
C-15	2024 Historic Year 2026 Projected Test Year 2027 Projected Test Year	INDUSTRY ASSOCIATION DUES
C-29	2026 Projected Test Year 2027 Projected Test Year	GAINS & LOSSES ON DISPOSITION OF PLANT AND PROPERTY
C-33	2026 Projected Test Year 2027 Projected Test Year	PERFORMANCE INDICES
C-37	2026 Projected Test Year 2027 Projected Test Year	O & M BENCHMARK COMPARISON BY FUNCTION
C-41	2026 Projected Test Year 2027 Projected Test Year	O & M BENCHMARK VARIANCE BY FUNCTION

FLORIDA POWER AND LIGHT COMPANY
IMPACTS TO DEPRECIATION EXPENSE USING 2025 DEPRECIATION STUDY DEPRECIATION RATES
BY YEAR FOR BASE VS. CLAUSE FOR 2026 AND 2027
($000)

Function	2026 Forecast (1)	2026 Depreciation Expense Related to Clauses (2)	Subtotal (1) + (2) = (3)	2026 Calculated Expense Using Proposed Rates (4)	2026 Calculated Expense Using Proposed Rates Related to Clauses (5)	2026 Base Expense (4) + (5) = (6)	2026 Company Adjustment (6) - (3) = (7)
STEAM	$ 112,414	$ (51,129)	$ 61,285	$ 137,736	$ (62,961)	$ 74,774	$ 13,489
NUCLEAR	236,066	(6,327)	229,739	251,954	(7,153)	244,801	15,063
OTHER PRODUCTION	610,759	(13,089)	597,670	621,191	(16,915)	604,276	6,606
TRANSMISSION	326,641	(9,774)	316,867	329,788	(10,393)	319,395	2,528
DISTRIBUTION	922,768	(153,473)	769,295	1,046,629	(180,442)	866,187	96,892
SOLAR	350,099	(7,053)	343,046	354,353	(7,859)	346,494	3,448
ENERGY STORAGE	77,339	-	77,339	78,035	-	78,035	696
OTHER RENEWABLE PRODUCTION	2,119	-	2,119	2,612	-	2,612	493
GENERAL	57,580	(147)	57,433	53,890	(169)	53,721	(3,712)
TOTAL	**$ 2,695,785**	**$ (240,993)**	**$ 2,454,792**	**$ 2,876,188**	**$ (285,893)**	**$ 2,590,295**	**$ 135,503**
	(A)	(A)		(B)			(C)

Function	2027 Forecast (1)	2027 Depreciation Expense Related to Clauses (2)	Subtotal (1) + (2) = (3)	2027 Calculated Expense Using Proposed Rates (4)	2027 Calculated Expense Using Proposed Rates Related to Clauses (5)	2027 Base Expense (4) + (5) = (6)	2027 Company Adjustment (6) - (3) = (7)
STEAM	$ 111,417	$ (51,321)	$ 60,097	$ 136,585	$ (63,485)	$ 73,100	$ 13,003
NUCLEAR	241,141	(6,428)	234,714	257,792	(7,281)	250,510	15,797
OTHER PRODUCTION	619,315	(12,710)	606,605	631,103	(16,533)	614,569	7,964
TRANSMISSION	354,325	(11,451)	342,874	358,586	(12,187)	346,399	3,525
DISTRIBUTION	978,255	(176,816)	801,439	1,108,084	(206,871)	901,213	99,775
SOLAR	381,714	(7,071)	374,643	385,751	(7,877)	377,874	3,231
ENERGY STORAGE	186,055	-	186,055	187,892	-	187,892	1,838
OTHER RENEWABLE PRODUCTION	2,271	-	2,271	2,943	-	2,943	673
GENERAL	61,343	(147)	61,196	57,399	(169)	57,230	(3,966)
TOTAL	**$ 2,935,836**	**$ (265,943)**	**$ 2,669,892**	**$ 3,126,134**	**$ (314,403)**	**$ 2,811,731**	**$ 141,839**
	(A)	(A)		(B)			(C)

Notes:
(A) Excludes amounts related to asset retirement obligations, acquisition adjustment, dismantlement, and amortizable property, which are included in the total amount forecasted for depreciation expense on MFR C-4.
(B) Calculated amounts are based on FPL's proposed depreciation rates included in its 2025 Depreciation Study.
(C) After-tax amount is reflected as a Per Book Company adjustment on MFR C-3.

FLORIDA POWER & LIGHT COMPANY
CHANGE IN FORECASTED ACCUMULATED DEPRECIATION
RESULTING FROM FPL'S PROPOSED CHANGE IN BASE DEPRECIATION EXPENSE AND RESERVE TRANSFERS
($000)

Function (A)	Ending Balance 12/31/2025	Ending Balance 1/31/2026	Ending Balance 2/28/2026	Ending Balance 3/31/2026	Ending Balance 4/30/2026	Ending Balance 5/31/2026	Ending Balance 6/30/2026	Ending Balance 7/31/2026	Ending Balance 8/31/2026	Ending Balance 9/30/2026	Ending Balance 10/31/2026	Ending Balance 11/30/2026	Ending Balance 12/31/2026	13-Month Average 2026
CHANGE IN DEPRECIATION EXPENSE														
STEAM	$ -	$ 1,130	$ 2,261	$ 3,396	$ 4,536	$ 5,655	$ 6,776	$ 7,902	$ 9,028	$ 10,155	$ 11,281	$ 12,409	$ 13,489	$ 6,771
NUCLEAR	-	1,235	2,471	3,710	4,954	6,202	7,454	8,708	9,963	11,226	12,497	13,774	15,063	7,481
OTHER PRODUCTION	-	588	1,177	1,769	2,332	2,862	3,358	3,860	4,373	4,894	5,441	6,014	6,606	3,329
TRANSMISSION	-	193	369	554	737	917	1,122	1,344	1,567	1,793	2,030	2,274	2,528	1,187
DISTRIBUTION	-	7,965	15,948	23,949	31,971	40,015	48,079	56,166	64,277	72,405	80,550	88,712	96,892	48,225
SOLAR	-	295	584	876	1,165	1,450	1,735	2,021	2,306	2,591	2,877	3,162	3,448	1,732
ENERGY STORAGE	-	34	68	102	136	171	205	255	322	390	468	575	696	263
OTHER RENEWABLE PRODUCTION	-	41	82	123	164	206	247	288	329	370	411	452	493	247
GENERAL	-	(297)	(596)	(896)	(1,200)	(1,508)	(1,818)	(2,131)	(2,445)	(2,760)	(3,076)	(3,393)	(3,712)	(1,833)
TOTAL CHANGE IN DEPRECIATION EXPENSE	$ -	$ 11,185	$ 22,365	$ 33,583	$ 44,796	$ 55,969	$ 67,157	$ 78,412	$ 89,719	$ 101,064	$ 112,480	$ 123,979	$ 135,503	$ 67,401
ACCUMULATED DEPRECIATION RESERVE TRANSFER														
STEAM	$ -	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (15,787)
OTHER PRODUCTION	-	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	15,787
TOTAL RESERVE TRANSFER	$ -	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RESERVE ADJUSTMENT	**$ -**	**$ 11,185**	**$ 22,365**	**$ 33,583**	**$ 44,796**	**$ 55,969**	**$ 67,157**	**$ 78,412**	**$ 89,719**	**$ 101,064**	**$ 112,480**	**$ 123,979**	**$ 135,503**	**$ 67,401**
														(B)

	Ending Balance 12/31/2026	Ending Balance 1/31/2027	Ending Balance 2/28/2027	Ending Balance 3/31/2027	Ending Balance 4/30/2027	Ending Balance 5/31/2027	Ending Balance 6/30/2027	Ending Balance 7/31/2027	Ending Balance 8/31/2027	Ending Balance 9/30/2027	Ending Balance 10/31/2027	Ending Balance 11/30/2027	Ending Balance 12/31/2027	13-Month Average 2027
CHANGE IN DEPRECIATION EXPENSE														
STEAM	$ 13,489	$ 14,570	$ 15,652	$ 16,734	$ 17,818	$ 18,903	$ 19,988	$ 21,076	$ 22,163	$ 23,251	$ 24,338	$ 25,427	$ 26,492	$ 19,993
NUCLEAR	15,063	16,360	17,660	18,962	20,269	21,581	22,897	24,216	25,536	26,858	28,183	29,513	30,859	22,920
OTHER PRODUCTION	6,606	7,266	7,930	8,597	9,280	9,911	10,566	11,196	11,836	12,482	13,124	13,831	14,570	10,553
TRANSMISSION	2,528	2,797	3,059	3,338	3,634	3,926	4,225	4,532	4,835	5,142	5,443	5,740	6,052	4,250
DISTRIBUTION	96,892	105,094	113,314	121,553	129,816	138,100	146,405	154,734	163,085	171,455	179,842	188,245	196,667	146,554
SOLAR	3,448	3,730	4,008	4,287	4,562	4,834	5,105	5,373	5,638	5,902	6,163	6,421	6,679	5,088
ENERGY STORAGE	696	818	940	1,062	1,198	1,347	1,497	1,659	1,832	2,006	2,181	2,358	2,534	1,548
OTHER RENEWABLE PRODUCTION	493	534	576	617	658	699	740	782	823	864	905	946	1,166	754
GENERAL	(3,712)	(4,034)	(4,356)	(4,678)	(5,004)	(5,333)	(5,664)	(5,997)	(6,332)	(6,666)	(7,002)	(7,339)	(7,678)	(5,677)
TOTAL CHANGE IN DEPRECIATION EXPENSE	$ 135,503	$ 147,135	$ 158,782	$ 170,471	$ 182,231	$ 193,967	$ 205,761	$ 217,570	$ 229,418	$ 241,294	$ 253,178	$ 265,143	$ 277,342	$ 205,984
ACCUMULATED DEPRECATION RESERVE TRANSFER														
STEAM	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)	$ (17,103)
OTHER PRODUCTION	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103	17,103
TOTAL RESERVE TRANSFER	$ -	-	-	-	-	-	-	-	-	-	-	-	-	-
TOTAL RESERVE ADJUSTMENT	**$ 135,503**	**$ 147,135**	**$ 158,782**	**$ 170,471**	**$ 182,231**	**$ 193,967**	**$ 205,761**	**$ 217,570**	**$ 229,418**	**$ 241,294**	**$ 253,178**	**$ 265,143**	**$ 277,342**	**$ 205,984**
														(C)

Notes:

(A) Positive amounts reflect increases to account balances and negative amounts reflect decreases to account balances.

(B) Reflected on MFR B-2 for the 2026 Projected Test Year as the Per Book depreciation study Company adjustment.

(C) Reflected on MFR B-2 for the 2027 Projected Test Year as the Per Book depreciation study Company adjustment.

Florida Power & Light Company
CAPITAL RECOVERY SCHEDULE BASE - SUMMARY

Line No.	Function	Exhibit Page Reference	(1) 2026 Current Base Depreciation/ Amortization (1)	(2) 2026 Proposed Base Amortization (2)	(3) 2026 Company Adjustment (2) - (1)	(4) 2027 Current Base Depreciation/ Amortization (1)	(5) 2027 Proposed Base Amortization (2)	(6) 2027 Company Adjustment (5) - (4)	(7) 2028 & 2029 Proposed Base Depreciation/ Amortization (2)
1	Steam Plant Retirements								
2	Daniel Units 1 & 2	Pg. 4	$ 9,882,899	$ 11,609,125	$ 1,726,226	$ 9,882,899	$ 11,609,125	$ 1,726,226	$ 11,609,125
3									
4	Transmission Plant Retirements								
5	500kV - 2024	Pg. 5	$ 369,744	$ 3,310,585	$ 2,940,841	$ 369,744	$ 3,310,585	$ 2,940,841	$ 3,310,585
6	500kV - 2025	Pg. 5	1,241,659	2,535,410	1,293,750	1,241,659	2,535,410	1,293,750	2,535,410
7	500kV - 2026	Pg. 5	-	996,085	996,085	-	996,085	996,085	996,085
8	500kV - 2027	Pg. 5	-	-	-	-	354,558	354,558	354,558
9	500kV - 2028	Pg. 5	-	-	-	-	-	-	660,619
10	Daniel Units 1 & 2	Pg. 4	216,312	428,511	212,199	216,312	428,511	212,199	428,511
11	Total for Transmission		$ 1,827,715	$ 7,270,591	$ 5,442,876	$ 1,827,715	$ 7,625,149	$ 5,797,433	$ 8,285,768
12									
13	General Plant Retirements								
14	Customer Information System	Pg. 6	$ -	$ -	$ -	$ -	$ 4,473,559	$ 4,473,559	$ 4,473,559
15									
16	Subtotal - All Functions		**$ 11,710,614**	**$ 18,879,716**	**$ 7,169,102**	**$ 11,710,614**	**$ 23,707,833**	**$ 11,997,218**	**$ 24,368,452**
17									
18	TOTAL BASE CAPITAL RECOVERY		**$ 11,710,614**	**$ 18,879,716**	**$ 7,169,102**	**$ 11,710,614**	**$ 23,707,833**	**$ 11,997,218**	**$ 24,368,452**
19									
20	Notes:								
21	(1) Amounts for the 500kV Tranches are based upon the depreciation rates approved by the FPSC in Order No. PSC-2021-0446-S-EI, and depreciation rates for Daniel Units 1 & 2 are based upon Gulf Power's 2017 Rate Settlement from Docket Nos. 20160186-EI and 20160170-EI.								
22	(2) Represents amortization based on 10-year amortization period as proposed by the Company.								

Florida Power & Light Company
CAPITAL RECOVERY SCHEDULE CLAUSE - SUMMARY

Line No.	Function	Exhibit Page Reference		(1) 2026 Current Clause Amortization (1)		(2) 2026 Proposed Clause Amortization (2)		(3) 2026 Clause Adjustment (2) - (1)		(4) 2027 Current Clause Amortization (1)		(5) 2027 Proposed Clause Amortization (2)		(6) 2027 Clause Adjustment (5) - (4)		(7) 2028 Proposed Clause Amortization
1	Steam Plant Retirements															
2	Daniel Units 1 & 2	Pg. 4	$	12,974,340	$	30,702,856	$	17,728,517		12,974,340	$	30,702,856	$	17,728,517	$	30,702,856
3																
4	**TOTAL CLAUSE CAPITAL RECOVERY**		**$**	**12,974,340**	**$**	**30,702,856**	**$**	**17,728,517**	**$**	**12,974,340**	**$**	**30,702,856**	**$**	**17,728,517**	**$**	**30,702,856**
5																

6 Notes:

7 (1) Amounts are based upon the depreciation rates approved in Gulf Power's 2017 Rate Settlement from Docket Nos. 20160186-EI and 20160170-EI.

8 (2) Represents amortization based on 10-year amortization period as proposed by the Company.

FLORIDA POWER & LIGHT COMPANY
CHANGE IN FORECASTED ACCUMULATED DEPRECIATION AND AMORTIZATION
RESULTING FROM FPL'S PROPOSED BASE CAPITAL RECOVERY SCHEDULES

Line No.	Function	Ending Balance 12/31/2025	Ending Balance 1/31/2026	Ending Balance 2/28/2026	Ending Balance 3/31/2026	Ending Balance 4/30/2026	Ending Balance 5/31/2026	Ending Balance 6/30/2026	Ending Balance 7/31/2026	Ending Balance 8/31/2026	Ending Balance 9/30/2026	Ending Balance 10/31/2026	Ending Balance 11/30/2026	Ending Balance 12/31/2026	13-Month Average 2026
1	Steam Plant Retirements														
2	Daniel Units 1 & 2	-	$ 143,852	$ 287,704	$ 431,557	$ 575,409	$ 719,261	$ 863,113	$ 1,006,965	$ 1,150,818	$ 1,294,670	$ 1,438,522	$ 1,582,374	$ 1,726,226	$ 863,113
3															
4	Transmission Plant Retirements														
5	500kV - 2024	-	245,070	490,140	735,210	980,280	1,225,350	1,470,421	1,715,491	1,960,561	2,205,631	2,450,701	2,695,771	2,940,841	$ 1,470,421
6	500kV - 2025	-	107,813	215,625	323,438	431,250	539,063	646,875	754,688	862,500	970,313	1,078,125	1,185,938	1,293,750	646,875
7	500kV - 2026	-	83,007	166,014	249,021	332,028	415,035	498,043	581,050	664,057	747,064	830,071	913,078	996,085	498,043
8	500kV - 2027	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Daniel Units 1 & 2	-	17,683	35,367	53,050	70,733	88,416	106,100	123,783	141,466	159,149	176,833	194,516	212,199	106,100
10															
11	General Plant Retirements														
12	Customer Information System	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13															
14	**TOTAL**	**$ -**	**$ 597,425**	**$ 1,194,850**	**$ 1,792,276**	**$ 2,389,701**	**$ 2,987,126**	**$ 3,584,551**	**$ 4,181,976**	**$ 4,779,401**	**$ 5,376,827**	**$ 5,974,252**	**$ 6,571,677**	**$ 7,169,102**	**$ 3,584,551**
15															**(1)**
16															
17															

Line No.	Function	Ending Balance 12/31/2026	Ending Balance 1/31/2027	Ending Balance 2/28/2027	Ending Balance 3/31/2027	Ending Balance 4/30/2027	Ending Balance 5/31/2027	Ending Balance 6/30/2027	Ending Balance 7/31/2027	Ending Balance 8/31/2027	Ending Balance 9/30/2027	Ending Balance 10/31/2027	Ending Balance 11/30/2027	Ending Balance 12/31/2027	13-Month Average 2027
21															
22															
23	Steam Plant Retirements														
24	Daniel Units 1 & 2	$ 1,726,226	$ 1,870,079	$ 2,013,931	$ 2,157,783	$ 2,301,635	$ 2,445,487	$ 2,589,339	$ 2,733,192	$ 2,877,044	$ 3,020,896	$ 3,164,748	$ 3,308,600	$ 3,452,453	$ 2,589,339
25															
26	Transmission Plant Retirements														
27	500kV - 2024	2,940,841	3,185,911	3,430,981	3,676,051	3,921,122	4,166,192	4,411,262	4,656,332	4,901,402	5,146,472	5,391,542	5,636,612	5,881,682	4,411,262
28	500kV - 2025	1,293,750	1,401,563	1,509,375	1,617,188	1,725,000	1,832,813	1,940,626	2,048,438	2,156,251	2,264,063	2,371,876	2,479,688	2,587,501	1,940,626
29	500kV - 2026	996,085	1,079,092	1,162,099	1,245,106	1,328,114	1,411,121	1,494,128	1,577,135	1,660,142	1,743,149	1,826,156	1,909,163	1,992,170	1,494,128
30	500kV - 2027	-	29,546	59,093	88,639	118,186	147,732	177,279	206,825	236,372	265,918	295,465	325,011	354,558	177,279
31	Daniel Units 1 & 2	212,199	229,882	247,566	265,249	282,932	300,615	318,299	335,982	353,665	371,348	389,032	406,715	424,398	318,299
32															
33	General Plant Retirements														
34	Customer Information System	-	372,797	745,593	1,118,390	1,491,186	1,863,983	2,236,779	2,609,576	2,982,372	3,355,169	3,727,966	4,100,762	4,473,559	2,236,779
35															
36	**TOTAL**	**$ 7,169,102**	**$ 8,168,870**	**$ 9,168,639**	**$ 10,168,407**	**$ 11,168,175**	**$ 12,167,943**	**$ 13,167,711**	**$ 14,167,480**	**$ 15,167,248**	**$ 16,167,016**	**$ 17,166,784**	**$ 18,166,552**	**$ 19,166,321**	**$ 13,167,711**
37															**(2)**
38															

39 **Notes:**
40 (1) Reflected on MFR B-2 for the 2026 Projected Test Year as the Per Book Capital Recovery Company adjustment.
41 (2) Reflected on MFR B-2 for the 2027 Projected Test Year as the Per Book Capital Recovery Company adjustment.

Florida Power & Light Company
CAPITAL RECOVERY SCHEDULE
Daniel Units 1 & 2 [1]

Line No.			(1) Total Unrecovered Cost [2]	÷	(2) Amortization Period	=	(3) Annual Accrual Amounts	(4) Current Amortization [3]	(5) Company Adjustment [4] (3) - (4)
1	**CAPITAL RECOVERY ACCOUNTS - BASE**								
2									
3	**Steam Plant Retirements**								
4	Daniel Common								
5	310	Land and land rights.	$ 4,157,703		10		$ 415,770	$ 1,080	$ 414,690
6	311	Structures & Improvements	1,295,244		10		129,524	457,886	(328,362)
7	312	Boiler Plant Equipment	16,474,285		10		1,647,429	1,279,163	368,266
8	314	Turbogenerator Units	985,743		10		98,574	119,975	(21,401)
9	315	Accessory Electric Equipment	4,624,776		10		462,478	167,856	294,622
10	316	Miscellaneous Power Plant Equipment	1,168,585		10		116,858	774,480	(657,622)
11		Daniel Common Total	$ 28,706,337				$ 2,870,634	$ 2,800,440	$ 70,193
12									
13	Daniel Unit 1								
14	311	Structures & Improvements	$ (521,146)		10		$ (52,115)	$ 272,989	$ (325,104)
15	312	Boiler Plant Equipment	20,858,826		10		2,085,883	1,751,356	334,527
16	314	Turbogenerator Units	9,318,128		10		931,813	795,520	136,293
17	315	Accessory Electric Equipment	1,643,078		10		164,308	346,253	(181,945)
18	316	Miscellaneous Power Plant Equipment	134,320		10		13,432	39,456	(26,024)
19		Daniel Unit 1 Total	$ 31,433,207				$ 3,143,321	$ 3,205,573	$ (62,252)
20									
21	Daniel Unit 2								
22	311	Structures & Improvements	$ (520,684)		10		$ (52,068)	$ 294,682	$ (346,751)
23	312	Boiler Plant Equipment	33,900,580		10		3,390,058	2,050,871	1,339,187
24	314	Turbogenerator Units	20,529,103		10		2,052,910	1,074,876	978,034
25	315	Accessory Electric Equipment	1,631,182		10		163,118	416,161	(253,043)
26	316	Miscellaneous Power Plant Equipment	411,529		10		41,153	40,296	857
27		Daniel Unit 2 Total	$ 55,951,709				$ 5,595,171	$ 3,876,886	$ 1,718,285
28									
29	Total for Steam Plant		$ 116,091,253				$ 11,609,125	$ 9,882,899	$ 1,726,226
30									
31	**Transmission Plant Retirements**								
32	Daniel Common								
33	352	Structures & Improvements	$ 20,134		10		$ 2,013	$ 4,248	$ (2,235)
34	353	Station Equipment	4,264,979		10		426,498	212,064	214,434
35		Daniel Common Total	$ 4,285,113				$ 428,511	$ 216,312	$ 212,199
36									
37									
38	**TOTAL CAPITAL RECOVERY ACCOUNTS - BASE**		**$ 120,376,365**				**$ 12,037,637**	**$ 10,099,211**	**$ 1,938,425**
39							-		
40									
41	**CAPITAL RECOVERY ACCOUNTS - CLAUSE**								
42									
43	**Steam Plant Retirements**								
44									
45	Daniel Common								
46	311	Structures & Improvements	$ 28,269,135		10		$ 2,826,914	$ 1,092,042	$ 1,734,872
47	312	Boiler Plant Equipment	150,447,108		10		15,044,711	6,456,116	8,588,595
48	315	Accessory Electric Equipment	12,844,701		10		1,284,470	517,384	767,087
49	316	Miscellaneous Power Plant Equipment	128,875		10		12,887	110,652	(97,764)
50		Daniel Common Total	$ 191,689,820				$ 19,168,982	$ 8,176,193	$ 10,992,789
51									
52	Daniel Unit 1								
53	311	Structures & Improvements	$ 237,721		10		$ 23,772	$ 10,139	$ 13,633
54	312	Boiler Plant Equipment	74,677,293		10		7,467,729	3,149,719	4,318,011
55	315	Accessory Electric Equipment	1,517,431		10		151,743	103,506	48,237
56	316	Miscellaneous Power Plant Equipment	438,081		10		43,808	14,972	28,836
57		Daniel Unit 1 Total	$ 76,870,527				$ 7,687,053	$ 3,278,336	$ 4,408,717
58									
59	Daniel Unit 2								
60	311	Structures & Improvements	$ -		10		$ -	$ -	$ -
61	312	Boiler Plant Equipment	38,484,622		10		3,848,462	1,517,381	2,331,082
62	315	Accessory Electric Equipment	-		10		-	-	-
63	316	Miscellaneous Power Plant Equipment	(16,405)		10		(1,640)	2,431	(4,071)
64		Daniel Unit 2 Total	$ 38,468,218				$ 3,846,822	$ 1,519,812	$ 2,327,010
65									
66	**TOTAL CAPITAL RECOVERY AMOUNT - CLAUSE**		**$ 307,028,564**				**$ 30,702,856**	**$ 12,974,340**	**$ 17,728,517**
67									
68									
69	**CAPITAL RECOVERY AMOUNT - TOTAL**		**$ 427,404,930**				**$ 42,740,493**	**$ 23,073,551**	**$ 19,666,942**
70									

71 **Notes:**
72 [1] Daniel was retired on January 2024.
73 [2] Reflects unrecovered costs as of December 31, 2025.
74 [3] Amounts are based upon Gulf Power's 2017 Rate Settlement from Docket Nos. 20160186-EI and 20160170-EI.
75 [4] Represents the difference between amortization based on rates as approved in Gulf Power's 2017 Rate Settlement and the 10-year amortization proposed by the Company.

Florida Power & Light Company
CAPITAL RECOVERY SCHEDULE
500 kV Transmission Rebuild Project

Line No.				(1) Original Cost	-	(2) Book Reserve	=	(3) Unrecovered Net Book Value	+	(4) Estimated Cost of Removal (COR)[1]	=	(5) Total Unrecovered Cost (3) + (4)	÷	(6) Amortization Period	=	(7) Annual Depreciation/Amortization Amounts	(8) Current Base Amortization[5]	(9) 2026 Company Adjustment[6] (7) - (8)	(10) 2027 Company Adjustment[6]
1	**CAPITAL RECOVERY ACCOUNTS - BASE**																		
2																			
3	**Transmission Plant Retirements**																		
4																			
5	Year 2024 [2]																		
6		354	Towers and Fixtures	-		-		-		-		$ 32,670,832		10		$ 3,267,083	$ 343,246	$ 2,923,838	$ 2,923,838
7		355	Poles and Fixtures	-		-		-		-		79,229		10		7,923	19,380	(11,458)	(11,458)
8		356	Overhead conductors and devices	-		-		-		-		355,789		10		35,579	7,118	28,461	28,461
9			500kV 2024 Total	-		-		-		-		$ 33,105,850				$ 3,310,585	$ 369,744	$ 2,940,841	$ 2,940,841
10																			
11	Year 2025 [2]																		
12		354	Towers and Fixtures	-		-		-		-		$ 23,763,814		10		$ 2,376,381	$ 1,221,053	$ 1,155,328	$ 1,155,328
13		355	Poles and Fixtures	-		-		-		-		1,590,282		10		159,028	20,606	138,422	138,422
14			500kV 2025 Total	-		-		-		-		$ 25,354,096				$ 2,535,410	$ 1,241,659	$ 1,293,750	$ 1,293,750
15																			
16																			
17	Year 2026 [3]																		
18		354	Towers and Fixtures	$ 32,014,175		$ 27,362,278		$ 4,651,896		$ 4,439,075		$ 9,090,972		10		$ 909,097	-	$ 909,097	$ 909,097
19		355	Poles and Fixtures	1,420,443		697,223		723,220		$ 146,660		869,880		10		86,988	-	86,988	86,988
20			500kV 2026 Total	$ 33,434,618		$ 28,059,502		$ 5,375,116		$ 4,585,735		$ 9,960,851				$ 996,085	$ -	$ 996,085	$ 996,085
21																			
22	Year 2027 [3]																		
23		354	Towers and Fixtures	$ -		$ -		$ -		$ 3,456,365		$ 3,456,365		10		$ 345,637	-	-	$ 345,637
24		355	Poles and Fixtures	-		-		-		89,211		89,211		10		8,921	-	-	8,921
25			500kV 2027 Total	$ -		$ -		$ -		$ 3,545,576		$ 3,545,576				$ 354,558	$ -	$ -	$ 354,558
26																			
27																			
28	Year 2028 [4]																		
29		354	Towers and Fixtures	$ 35,040,530		$ 19,057,248		$ 15,983,282		$ 3,375,182		$ 19,358,464		1.82%		$ 637,738	-	-	-
30		355	Poles and Fixtures	904,417		473,158		431,259		87,115		518,374		2.53%		22,882	-	-	-
31			500kV 2028 Total	$ 35,944,947		$ 19,530,407		$ 16,414,540		$ 3,462,297		$ 19,876,838				$ 660,619	$ -	$ -	$ -
32																			
33																			
34	**TOTAL CAPITAL RECOVERY AMOUNTS - BASE**			**$ 69,379,565**		**$ 47,589,908**		**$ 21,789,657**		**$ 11,593,609**		**$ 91,843,212**					**$ 1,611,403**	**$ 5,230,677**	**$ 5,585,234**
35																			

36 **Notes:**

37 [1] Due to the nature of these retirements, the Capital Recovery Schedule amounts reflect unrecovered Net Book Value and estimated Cost of Removal (COR).

38 [2] Represents unrecovered costs as of December 31, 2025.

39 [3] Represents retirements performed during the prior year. Retirements occur when phases of the 500 kV project are placed in-service.

40 [4] Retirements completed during 2027 which will be amortized using the proposed 2025 Depreciation Study rates, beginning in January 2028. No more retirements are expected for the project beyond 2028.

41 [5] Represents amortization based on current RSAM approved depreciation rates from Docket No. 20210015-EI.

42 [6] Represents the difference between amortization at current approved RSAM rates and the 10-year amortization proposed by the Company.

Florida Power & Light Company
CAPITAL RECOVERY SCHEDULE
Customer Information System ("CIS") [(1)]

Line No.		(1) Original Cost	-	(2) Book Reserve	=	(3) Total Unrecovered Cost	÷	(4) Amortization Period	=	(5) Annual Amortization Amounts
1	**CAPITAL RECOVERY ACCOUNTS - BASE**									
2										
3	General Plant Retirements									
4	Customer Information System									
5	397.2 Computer Software	$ 140,851,134		$ 96,115,547		$ 44,735,587		10		$ 4,473,559
6										
7	**TOTAL CAPITAL RECOVERY ACCOUNTS - BASE**	**$ 140,851,134**		**$ 96,115,547**		**$ 44,735,587**				**$ 4,473,559**
8										
9										
10	**Notes:**									
11	[(1)] Retirement date for the CIS is expected to be December 2026; therefore, amortization will begin in January 2027.									

FLORIDA POWER & LIGHT COMPANY
2026 AND 2027 DISMANTLEMENT ACCRUAL COMPANY ADJUSTMENT

Line No.	Plant Site (1)	Base/Clause	Function	Currently Approved Annual Accrual (2)	Proposed Annual Accrual Effective 1/1/2026	Increase/ (Decrease) in Annual Dismantlement Accrual
1	Cape Canaveral	Base	Other	$ 620,112	$ 602,601	$ (17,512)
2	Gulf Clean Energy Center	Base	Other	76,675	115,452	38,777
3	Dania Beach	Base	Other	257,906	541,462	283,556
4	Ft. Myers	Base	Other	1,235,668	1,547,723	312,055
5	Lauderdale	Base	Other	541,150	219,230	(321,919)
6	Martin	Base	Other	1,690,540	1,612,125	(78,415)
7	Manatee	Base	Other	789,597	915,129	125,532
8	Okeechobee	Base	Other	945,661	1,061,524	115,863
9	Pace/Pea Ridge Cogen	Base	Other	2,080	(0)	(2,081)
10	Port Everglades	Base	Other	437,855	531,956	94,101
11	Riviera Beach	Base	Other	345,018	502,717	157,699
12	Sanford	Base	Other	979,952	1,203,591	223,639
13	Smith	Base	Other	-	678,850	678,850
14	Turkey Point	Base	Other	405,412	701,956	296,544
15	West County Energy Center	Base	Other	1,299,542	1,946,326	646,785
16	Total Other			$ 9,627,168	$ 12,180,641	$ 2,553,474
17						
18	Gulf Clean Energy Center	Base	Steam	$ 1,487,736	$ 3,155,553	$ 1,667,817
19	Daniel	Base	Steam	787,184	367,779	(419,405)
20	Manatee	Base	Steam	-	1,449,911	1,449,911
21	Scherer	Base	Steam	2,007,354	1,025,840	(981,514)
22	Total Steam			$ 4,282,273	$ 5,999,082	$ 1,716,808
23						
24	Solar	Base	Solar	$ 21,479,964	$ 60,411,234	$ 38,931,270
25						
26	Cavendish Hydrogen	Base	Other Renewable Production	$ -	$ 89,801	$ 89,801
27	Perdido Landfill	Base	Other Renewable Production	20,252	24,868	4,617
28	Total Other Renewable Production			$ 20,252	$ 114,669	$ 94,417
29						
30	Battery Storage	Base	Energy Storage	$ 1,235,375	$ 17,495,601	$ 16,260,227
31						
32	**Total Increase in Base Rate Dismantlement Accrual (3)**			**$ 36,645,032**	**$ 96,201,228**	**$ 59,556,196**
33						
34	Solar (4)	Clause	Solar	$ 680,818	$ 152,293	$ (528,525)
35	Daniel (Coal Combustion Residuals)	Clause	Steam	-	352,306	352,306
36	Gulf Clean Energy Center (Coal Combustion Residuals)	Clause	Steam	-	46,497	46,497
37	Scherer - Unit 3 (Coal Combustion Residuals)	Clause	Steam	2,553,939	2,386,039	(167,900)
38	Scherer - Unit 4 (Coal Combustion Residuals)	Clause	Steam	7,800,751	7,287,918	(512,832)
39	**Total Decrease in Clause Dismantlement Accrual**			**$ 11,035,507**	**$ 10,225,053**	**$ (810,454)**
40						
41	**Total Increase in Dismantlement Accrual**			**$ 47,680,539**	**$ 106,426,281**	**$ 58,745,742**
42						

43	Function	Clause/Base	12/31/25 Estimated Reserve (Pre-Transfers)	Proposed Reserve Transfers (5)	12/31/25 Estimated Reserve (Post-Transfers)
44	Other	Base	$ 36,338,039	$ 6,205,661	$ 42,543,700
45	Other Renewable Production	Base	317,775	55,252	373,027
46	Steam	Base	111,799,151	67,513,060	179,312,211
47	Solar	Base	85,919,856	(85,919,856)	-
48	Energy Storage - Battery	Base	4,941,499	(334,645)	4,606,854
49	**Subtotal - Reserve Transfers (Base)**		**$ 239,316,320**	**$ (12,480,527)**	**$ 226,835,793**
50	Steam	Clause	$ 102,841,745	$ 7,267,140	$ 110,108,885
51	Solar	Clause	(2,093,837)	5,213,388	3,119,550
52	**Subtotal - Reserve Transfers (Clause)**		**$ 100,747,908**	**$ 12,480,527**	**$ 113,228,435**
53	**Total Dismantlement Reserve Transfers**		**$ 340,064,228**	**$ -**	**$ 340,064,228**

54

55 **Notes:**

56 (1) See FPL's 2025 Dismantlement Study at Exhibit NWA-2 for further detail regarding sites added since the 2021 Dismantlement Study.

57 (2) FPL accrual amount approved by Order Nos. PSC-2021-0446-S-EI and amended Order PSC-2021-0446A-S-EI in Docket No. 20210015-EI.

58 (3) After-tax amount of $44.5 million is reflected as a Per Book Company Adjustment on MFR C-3 for both the 2026 Projected Test Year and 2027 Projected Test Year.

59 (4) Solar includes Martin, Desoto and Space Coast recovered through the Environmental Cost Recovery Clause per FPSC Order No. 08-0491-PAA-EI. Note, Martin Solar Plant has been retired and will be dismantled by the end of 2025.

60 (5) Dismantlement reserve transfers from Base to Clause. MFR B-2 reflects 13-month average of reserve transfers from Base to Clause.

FLORIDA POWER & LIGHT COMPANY
CHANGE IN FORECASTED ACCUMULATED DISMANTLEMENT
RESULTING FROM FPL'S PROPOSED CHANGE IN BASE DISMANTLEMENT EXPENSE AND RESERVE TRANSFERS

Line No.	Function [(1)]	Ending Balance 12/31/2025	Ending Balance 1/31/2026	Ending Balance 2/28/2026	Ending Balance 3/31/2026	Ending Balance 4/30/2026	Ending Balance 5/31/2026	Ending Balance 6/30/2026	Ending Balance 7/31/2026	Ending Balance 8/31/2026	Ending Balance 9/30/2026	Ending Balance 10/31/2026	Ending Balance 11/30/2026	Ending Balance 12/31/2026	13-Month Average 2026
1	CHANGE IN DISMANTLEMENT EXPENSE														
3	OTHER PRODUCTION	$ -	$ 212,789	$ 425,579	$ 638,368	$ 851,158	$ 1,063,947	$ 1,276,737	$ 1,489,526	$ 1,702,316	$ 1,915,105	$ 2,127,895	$ 2,340,684	$ 2,553,474	$ 1,276,737
5	STEAM	-	143,067	286,135	429,202	572,269	715,337	858,404	1,001,472	1,144,539	1,287,606	1,430,674	1,573,741	1,716,808	858,404
7	SOLAR	-	3,244,272	6,488,545	9,732,817	12,977,090	16,221,362	19,465,635	22,709,907	25,954,180	29,198,452	32,442,725	35,686,997	38,931,270	19,465,635
9	OTHER RENEWABLE PRODUCTION	-	7,868	15,736	23,604	31,472	39,341	47,209	55,077	62,945	70,813	78,681	86,549	94,417	47,209
11	ENERGY STORAGE	-	1,355,019	2,710,038	4,065,057	5,420,076	6,775,094	8,130,113	9,485,132	10,840,151	12,195,170	13,550,189	14,905,208	16,260,227	8,130,113
13	TOTAL CHANGE IN DISMANTLEMENT EXPENSE	$ -	$ 4,963,016	$ 9,926,033	$ 14,889,049	$ 19,852,065	$ 24,815,082	$ 29,778,098	$ 34,741,114	$ 39,704,130	$ 44,667,147	$ 49,630,163	$ 54,593,179	$ 59,556,196	$ 29,778,098
15	ACCUMULATED DISMANTLEMENT RESERVE TRANSFER														
17	OTHER PRODUCTION	$ -	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	5,728,303
19	STEAM	-	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	62,319,748
21	SOLAR	-	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(79,310,637)
23	OTHER RENEWABLE PRODUCTION	-	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	51,002
25	ENERGY STORAGE	-	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(308,903)
27	TOTAL DISMANTLEMENT RESERVE TRANSFER	$ -	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (11,520,487)
29	**TOTAL DISMANTLEMENT RESERVE ADJUSTMENT**	**$ -**	**$ (7,517,511)**	**$ (2,554,494)**	**$ 2,408,522**	**$ 7,371,538**	**$ 12,334,555**	**$ 17,297,571**	**$ 22,260,587**	**$ 27,223,603**	**$ 32,186,620**	**$ 37,149,636**	**$ 42,112,652**	**$ 47,075,669**	**$ 18,257,611**
30															**(2)**

Line No.	Function	Ending Balance 12/31/2026	Ending Balance 1/31/2027	Ending Balance 2/28/2027	Ending Balance 3/31/2027	Ending Balance 4/30/2027	Ending Balance 5/31/2027	Ending Balance 6/30/2027	Ending Balance 7/31/2027	Ending Balance 8/31/2027	Ending Balance 9/30/2027	Ending Balance 10/31/2027	Ending Balance 11/30/2027	Ending Balance 12/31/2027	13-Month Average 2027
37	CHANGE IN DISMANTLEMENT EXPENSE														
39	OTHER PRODUCTION	$ 2,553,474	$ 2,766,263	$ 2,979,052	$ 3,191,842	$ 3,404,631	$ 3,617,421	$ 3,830,210	$ 4,043,000	$ 4,255,789	$ 4,468,579	$ 4,681,368	$ 4,894,158	$ 5,106,947	$ 3,830,210
41	STEAM	1,716,808	1,859,876	2,002,943	2,146,011	2,289,078	2,432,145	2,575,213	2,718,280	2,861,347	3,004,415	3,147,482	3,290,550	3,433,617	2,575,213
43	SOLAR	38,931,270	42,175,542	45,419,815	48,664,087	51,908,360	55,152,632	58,396,904	61,641,177	64,885,449	68,129,722	71,373,994	74,618,267	77,862,539	58,396,904
45	OTHER RENEWABLE PRODUCTION	94,417	102,286	110,154	118,022	125,890	133,758	141,626	149,494	157,362	165,230	173,099	180,967	188,835	141,626
47	ENERGY STORAGE	16,260,227	17,615,246	18,970,264	20,325,283	21,680,302	23,035,321	24,390,340	25,745,359	27,100,378	28,455,397	29,810,416	31,165,434	32,520,453	24,390,340
49	TOTAL CHANGE IN DISMANTLEMENT EXPENSE	$ 59,556,196	$ 64,519,212	$ 69,482,228	$ 74,445,245	$ 79,408,261	$ 84,371,277	$ 89,334,294	$ 94,297,310	$ 99,260,326	$ 104,223,343	$ 109,186,359	$ 114,149,375	$ 119,112,391	$ 89,334,294
51	ACCUMULATED DISMANTLEMENT RESERVE TRANSFER														
53	OTHER PRODUCTION	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661	$ 6,205,661
55	STEAM	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060	67,513,060
57	SOLAR	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)	(85,919,856)
59	OTHER RENEWABLE PRODUCTION	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252	55,252
61	ENERGY STORAGE	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)	(334,645)
63	TOTAL DISMANTLEMENT RESERVE TRANSFER	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)	$ (12,480,527)
65	**TOTAL DISMANTLEMENT RESERVE ADJUSTMENT**	**$ 47,075,669**	**$ 52,038,685**	**$ 57,001,701**	**$ 61,964,718**	**$ 66,927,734**	**$ 71,890,750**	**$ 76,853,767**	**$ 81,816,783**	**$ 86,779,799**	**$ 91,742,816**	**$ 96,705,832**	**$ 101,668,848**	**$ 106,631,864**	**$ 76,853,767**
66															**(3)**

68 Notes:
69 [(1)] Positive amounts reflect increases to account balances and negative amounts reflect decreases to account balances.
70 [(2)] Reflected on MFR B-2 for the 2026 Projected Test Year as the Per Book Dismantlement study Company adjustment.
71 [(3)] Reflected on MFR B-2 for the 2027 Projected Test Year as the Per Book Dismantlement study Company adjustment.

FLORIDA POWER AND LIGHT COMPANY
PROPOSED COMPANY ADJUSTMENT
TO MOVE SPP COST OF REMOVAL ("COR") AND RETIREMENTS FROM BASE TO SPPCRC
BY YEAR FOR 2026 AND 2027

Line No.	Function	2026 Forecast SPP Retirements Company Adjustment (1)	2026 Forecast Total Retirements (2)	% of SPP Retirements to Total Retirements (1) / (2) = (3)	2026 Forecasted Total COR (4)	2026 Forecasted SPP COR Company Adjustment (3) X (4) = (5)
1	**TRANSMISSION**					
2	352 Structures & Improvements	$ -	$ 437,868	0.00%	$ 43,433	$ -
3	353 Station Equipment	16,309	25,439,889	0.06%	3,003,761	1,926
4	353.1 Station Equipt-Gen Step-Up	-	914,744	0.00%	-	-
5	354 Towers & Fixtures	-	536,447	0.00%	10,193,438	-
6	355 Poles & Fixtures	1,107,467	15,621,194	7.09%	23,663,847	1,677,652
7	356 Overhead Cond & Devices	328,846	7,295,991	4.51%	12,711,235	572,922
8	357 Underground Conduit	-	10,727	0.00%	8,307	-
9	358 Underground Conduct & Device	-	2,696,702	0.00%	597,073	-
10	**TOTAL TRANSMISSION**	$ 1,452,621	$ 52,953,562	2.74%	$ 50,221,093	$ 2,252,499
11						
12	**DISTRIBUTION**					
13	361 Structures & Improvements	$ 29,479	$ 535,975	5.50%	$ 85,759	$ 4,717
14	362 Station Equipment	22,929	29,353,429	0.08%	4,696,719	3,669
15	364.1 Poles, Towers & Fix - Wood	700,257	11,993,083	5.84%	8,295,253	484,347
16	364.2 Poles, Towers & Fix - Conc	1,401,598	6,182,913	22.67%	4,276,534	969,443
17	365 Overhead Cond & Devices	6,369,636	63,536,502	10.03%	43,946,280	4,405,685
18	366.6 Underground Conduit (Duct Sys)	273,055	708,390	38.55%	489,972	188,864
19	366.7 Underground Conduit (Direct Buried)	2,501	26,024	9.61%	18,000	1,730
20	367.6 Underground Cond & Device (Duct Sys)	1,778,533	12,061,662	14.75%	8,342,688	1,230,158
21	367.7 Underground Cond & Device (Direct)	11,604	3,570,766	0.32%	2,469,791	8,026
22	368 Line Transformers	4,550,385	65,587,708	6.94%	45,365,038	3,147,364
23	369.1 Services, Overhead	13,528	3,257,787	0.42%	2,253,313	9,357
24	369.6 Services, Underground (In Duct)	1,354,260	6,019,712	22.50%	4,163,653	936,701
25	370 Meters	50	55,421	0.09%	38,333	35
26	370.1 Meters-AMI	-	23,934,996	0.00%	16,555,114	-
27	371 Installations On Cust Prem	31,548	452,185	6.98%	312,763	21,821
28	373 Street Lights & Signal Sys	237,470	16,517,579	1.44%	11,424,711	164,251
29	**TOTAL DISTRIBUTION**	$ 16,776,833	$ 243,794,132	6.88%	$ 152,733,921	$ 11,576,165
30						
31	**TOTAL**	**$ 18,229,454**	**$ 296,747,693**	**6.14%**	**$ 202,955,014**	**$ 13,828,664**
32		(A)	(B)		(B)	
33						
34						

Line No.	Function	2027 Forecast SPP Retirements Company Adjustment (1)	2027 Forecast Total Retirements (2)	% of SPP Retirements to Total Retirements (1) / (2) = (3)	2027 Forecast Total COR (4)	2027 Forecasted SPP COR Company Adjustment (3) X (4) = (5)
35–40	Function	(1)	(2)	(1) / (2) = (3)	(4)	(3) X (4) = (5)
41						
42	**TRANSMISSION**					
43	352 Structures & Improvements	$ -	$ 437,868	0.00%	$ 49,533	$ -
44	353 Station Equipment	28,726	25,439,889	0.11%	4,750,062	5,363.58
45	353.1 Station Equipt-Gen Step-Up	-	914,744	0.00%	-	-
46	354 Towers & Fixtures	-	536,447	0.00%	8,111,557	-
47	355 Poles & Fixtures	1,406,814	15,621,194	9.01%	19,807,891	1,783,859
48	356 Overhead Cond & Devices	332,197	7,295,991	4.55%	11,443,898	521,057.04
49	357 Underground Conduit	-	10,727	0.00%	6,606	-
50	358 Underground Conduct & Device	-	2,696,702	0.00%	781,702	-
51	**TOTAL TRANSMISSION**	$ 1,767,736	$ 52,953,562	3.34%	$ 44,951,250	$ 2,310,280
52						
53	**DISTRIBUTION**					
54	361 Structures & Improvements	$ 40,124	$ 535,975	7.49%	$ 117,902	$ 8,826
55	362 Station Equipment	25,077	29,353,429	0.09%	6,457,081	5,516
56	364.1 Poles, Towers & Fix - Wood	856,094	11,993,083	7.14%	8,881,003	633,947
57	364.2 Poles, Towers & Fix - Conc	1,900,543	6,182,913	30.74%	4,578,511	1,407,372
58	365 Overhead Cond & Devices	7,504,290	63,536,502	11.81%	47,049,440	5,557,005
59	366.6 Underground Conduit (Duct Sys)	370,854	708,390	52.35%	524,570	274,621
60	366.7 Underground Conduit (Direct Buried)	3,746	26,024	14.39%	19,271	2,774
61	367.6 Underground Cond & Device (Duct Sys)	2,426,750	12,061,662	20.12%	8,931,786	1,797,033
62	367.7 Underground Cond & Device (Direct)	15,735	3,570,766	0.44%	2,644,189	11,652
63	368 Line Transformers	5,569,158	65,587,708	8.49%	48,568,380	4,124,019
64	369.1 Services, Overhead	17,334	3,257,787	0.53%	2,412,425	12,836
65	369.6 Services, Underground (In Duct)	1,834,382	6,019,712	30.47%	4,457,659	1,358,379
66	370 Meters	72	55,421	0.13%	41,040	53
67	370.1 Meters-AMI	-	23,934,996	0.00%	17,724,114	-
68	371 Installations On Cust Prem	39,469	452,185	8.73%	334,848	29,227
69	373 Street Lights & Signal Sys	282,729	16,517,579	1.71%	12,231,439	209,364
70	**TOTAL DISTRIBUTION**	$ 20,886,356	$ 243,794,132	8.57%	$ 164,973,659	$ 15,432,625
71						
72	**TOTAL**	**$ 22,654,092**	**$ 296,747,693**	**7.63%**	**$ 209,924,909**	**$ 17,742,904**
73		(A)	(B)		(B)	
74						
75						

76 **Notes:**
77 (A) Estimated SPP retirements provided by Gannett Fleming. Amounts were estimated by applying the Iowa curves used in calculating the RSAM depreciation rates approved
78 by the FPSC in the 2021 Rate Case to forecasted SPP activity.
79 (B) Amounts exclude 500 kV retirements and cost of removal.

FLORIDA POWER & LIGHT COMPANY
CHANGE IN FORECASTED PLANT IN SERVICE AND ACCUMULATED DEPRECIATION
RESULTING FROM FPL'S PROPOSED COMPANY ADJUSTMENT TO MOVE SPP RETIREMENTS AND COR FROM BASE TO SPPCRC

Line No.	Function (A)	Ending Balance 12/31/2025	Ending Balance 1/31/2026	Ending Balance 2/28/2026	Ending Balance 3/31/2026	Ending Balance 4/30/2026	Ending Balance 5/31/2026	Ending Balance 6/30/2026	Ending Balance 7/31/2026	Ending Balance 8/31/2026	Ending Balance 9/30/2026	Ending Balance 10/31/2026	Ending Balance 11/30/2026	Ending Balance 12/31/2026	13-Month Average 2026
1	CHANGE IN PLANT IN SERVICE - RETIREMENT														
3	TRANSMISSION	$ -	$ 121,052	$ 242,104	$ 363,155	$ 484,207	$ 605,259	$ 726,311	$ 847,362	$ 968,414	$ 1,089,466	$ 1,210,518	$ 1,331,569	$ 1,452,621	$ 726,311
5	DISTRIBUTION	-	1,398,069	2,796,139	4,194,208	5,592,278	6,990,347	8,388,416	9,786,486	11,184,555	12,582,625	13,980,694	15,378,764	16,776,833	8,388,416
7	**TOTAL CHANGE IN PLANT IN SERVICE**	**$ -**	**$ 1,519,121**	**$ 3,038,242**	**$ 4,557,363**	**$ 6,076,485**	**$ 7,595,606**	**$ 9,114,727**	**$ 10,633,848**	**$ 12,152,969**	**$ 13,672,090**	**$ 15,191,212**	**$ 16,710,333**	**$ 18,229,454**	**$ 9,114,727**
8															**(B)**
10	CHANGE IN ACCUMULATED DEPRECIATION RESERVE - RETIREMENTS														
12	TRANSMISSION	$ -	$ 121,052	$ 242,104	$ 363,155	$ 484,207	$ 605,259	$ 726,311	$ 847,362	$ 968,414	$ 1,089,466	$ 1,210,518	$ 1,331,569	$ 1,452,621	$ 726,311
14	DISTRIBUTION	-	1,398,069	2,796,139	4,194,208	5,592,278	6,990,347	8,388,416	9,786,486	11,184,555	12,582,625	13,980,694	15,378,764	16,776,833	8,388,416
16	**TOTAL ACCUMULATED DEPRECIATION RESERVE - RETIREMENTS**	**$ -**	**$ 1,519,121**	**$ 3,038,242**	**$ 4,557,363**	**$ 6,076,485**	**$ 7,595,606**	**$ 9,114,727**	**$ 10,633,848**	**$ 12,152,969**	**$ 13,672,090**	**$ 15,191,212**	**$ 16,710,333**	**$ 18,229,454**	**$ 9,114,727**
17															**(B)**
19	CHANGE IN ACCUMULATED DEPRECIATION RESERVE - COR														
21	TRANSMISSION	$ -	$ 234,266	$ 460,560	$ 719,824	$ 953,747	$ 1,161,011	$ 1,373,358	$ 1,535,754	$ 1,686,683	$ 1,838,807	$ 1,992,103	$ 2,124,389	$ 2,252,499	$ 1,256,385
23	DISTRIBUTION	-	956,012	1,902,109	2,868,362	3,847,075	4,805,951	5,766,108	6,737,743	7,725,982	8,704,964	9,684,469	10,630,156	11,576,165	5,785,007
25	**TOTAL ACCUMULATED DEPRECIATION RESERVE - COR**	**$ -**	**$ 1,190,278**	**$ 2,362,668**	**$ 3,588,186**	**$ 4,800,822**	**$ 5,966,962**	**$ 7,139,466**	**$ 8,273,497**	**$ 9,412,665**	**$ 10,543,771**	**$ 11,676,572**	**$ 12,754,545**	**$ 13,828,664**	**$ 7,041,392**
26															**(B)**

Line No.	Function (A)	Ending Balance 12/31/2026	Ending Balance 1/31/2027	Ending Balance 2/28/2027	Ending Balance 3/31/2027	Ending Balance 4/30/2027	Ending Balance 5/31/2027	Ending Balance 6/30/2027	Ending Balance 7/31/2027	Ending Balance 8/31/2027	Ending Balance 9/30/2027	Ending Balance 10/31/2027	Ending Balance 11/30/2027	Ending Balance 12/31/2027	13-Month Average 2027
34	CHANGE IN PLANT IN SERVICE - RETIREMENT														
37	TRANSMISSION	$ 1,452,621	$ 1,599,932	$ 1,747,244	$ 1,894,555	$ 2,041,866	$ 2,189,178	$ 2,336,489	$ 2,483,800	$ 2,631,112	$ 2,778,423	$ 2,925,734	$ 3,073,046	$ 3,220,357	$ 2,336,489
39	DISTRIBUTION	16,776,833	18,517,363	20,257,892	21,998,422	23,738,952	25,479,481	27,220,011	28,960,541	30,701,070	32,441,600	34,182,130	35,922,659	37,663,189	27,220,011
42	**TOTAL CHANGE IN PLANT IN SERVICE**	**$ 18,229,454**	**$ 20,117,295**	**$ 22,005,136**	**$ 23,892,977**	**$ 25,780,818**	**$ 27,668,659**	**$ 29,556,500**	**$ 31,444,341**	**$ 33,332,182**	**$ 35,220,023**	**$ 37,107,864**	**$ 38,995,705**	**$ 40,883,546**	**$ 29,556,500**
43															**(C)**
45	CHANGE IN ACCUMULATED DEPRECIATION RESERVE - RETIREMENTS														
47	TRANSMISSION	$ 1,452,621	$ 1,599,932	$ 1,747,244	$ 1,894,555	$ 2,041,866	$ 2,189,178	$ 2,336,489	$ 2,483,800	$ 2,631,112	$ 2,778,423	$ 2,925,734	$ 3,073,046	$ 3,220,357	$ 2,336,489
49	DISTRIBUTION	16,776,833	18,517,363	20,257,892	21,998,422	23,738,952	25,479,481	27,220,011	28,960,541	30,701,070	32,441,600	34,182,130	35,922,659	37,663,189	27,220,011
51	**TOTAL ACCUMULATED DEPRECIATION RESERVE - RETIREMENTS**	**$ 18,229,454**	**$ 20,117,295**	**$ 22,005,136**	**$ 23,892,977**	**$ 25,780,818**	**$ 27,668,659**	**$ 29,556,500**	**$ 31,444,341**	**$ 33,332,182**	**$ 35,220,023**	**$ 37,107,864**	**$ 38,995,705**	**$ 40,883,546**	**$ 29,556,500**
52															**(C)**
54	CHANGE IN ACCUMULATED DEPRECIATION RESERVE - COR														
56	TRANSMISSION	$ 2,252,499	$ 2,433,922	$ 2,620,241	$ 2,817,356	$ 3,013,085	$ 3,206,496	$ 3,418,551	$ 3,608,943	$ 3,799,315	$ 3,991,479	$ 4,182,992	$ 4,374,550	$ 4,562,779	$ 3,406,324
58	DISTRIBUTION	11,576,165	12,846,361	14,106,444	15,390,587	16,683,039	17,962,375	19,281,477	20,623,162	21,973,043	23,267,773	24,549,652	25,788,982	27,008,790	19,312,142
60	**TOTAL ACCUMULATED DEPRECIATION RESERVE - COR**	**$ 13,828,664**	**$ 15,280,282**	**$ 16,726,685**	**$ 18,207,943**	**$ 19,696,124**	**$ 21,168,871**	**$ 22,700,028**	**$ 24,232,105**	**$ 25,772,358**	**$ 27,259,252**	**$ 28,732,644**	**$ 30,163,532**	**$ 31,571,569**	**$ 22,718,466**
61															**(C)**

63 **Notes:**
64 (A) Positive amounts reflect increases to account balances and negative amounts reflect decreases to account balances.
65 (B) Reflected on MFR B-2 for the 2026 Projected Test Year.
66 (C) Reflected on MFR B-2 for the 2027 Projected Test Year.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

I. INTRODUCTION

This Cost Allocation Manual (CAM) documents cost allocation policies and practices and provides guidelines to employees regarding the application of those policies for affiliate transactions.

The over-riding principle of this process is that resources shared between Florida Power & Light (FPL) and its affiliates cannot result in subsidization by the regulated entity on behalf of its non-regulated affiliates. This manual describes the standard services provided between FPL and its affiliates, as well as FPL's inter-company process for charging direct and indirect costs, the Corporate Services Charge (CSC), and other apportionment methods. The costing concepts and principles described herein are applied consistently to all affiliates billed by FPL.

When affiliates request services from FPL personnel, FPL employees should direct charge for services provided to the benefiting affiliate. This manual describes processes to direct charge those costs, as well as the allocation processes used when direct charging is not practical.

II. COST ACCOUNTING CONCEPTS

Costs are apportioned among entities based on three cost characteristics:

- **Direct** – Costs of resources used exclusively for the provision of services that are readily identifiable to an activity. An example of inter-company direct costs would be the fully-loaded salary of an engineer working on an affiliate's power plant.

- **Assigned** – Costs of resources used jointly in the provision of both regulated and non-regulated activities that are apportioned using direct measures of cost causation. The square footage cost of office space used by affiliates would be an example of assignable costs. These costs are directly billed to affiliates or allocated using the CSC.

- **Unattributable** – Cost of resources shared by both regulated and non-regulated activities for which no causal relationship can be practicably identified. These costs are accumulated and allocated to both regulated and non-regulated activities through the use of the CSC. The costs associated with NextEra Energy, Inc.'s board of directors is an example of unattributable costs.

III. REGULATORY REQUIREMENTS AND REPORTING

A. FERC Accounting Guidelines

The Uniform System of Accounts (USOA), as prescribed by the Federal Energy Regulatory Commission (FERC) and adopted by the Florida Public Service Commission (FPSC), is found in the Code of Federal Regulations, Title 18, Subchapter C. Part 101. Application of these guidelines indicates that:

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

- Inter-company transactions for services provided to affiliates are to be recorded in FERC account 146.
- Inter-company transactions for services provided by affiliates to the regulated utility are to be recorded in the appropriate account within the operational function receiving the goods or services, or to FERC account 923 for Administrative & General support.
- Intra-Utility direct charge transactions are to be recorded in the appropriate account(s) within the operational function receiving the goods or services.
- Intra-Utility allocations of corporate center costs for business unit financial reporting are to be recorded in the Administrative and General (A&G) range of accounts. Administrative and general accounts should contain charges not chargeable directly to a particular operating function.

FERC recognizes explicitly in Order 707-A that the “at cost” pricing rules would be extended to single state holding companies that do not have centralized shared services companies. An important condition to this rule, however, is that such services may not be provided to unaffiliated third parties. The reason for this condition is that a market price is determinable in cases where such services are provided to third parties. FPL currently qualifies for the single state exemption, therefore, activities between FPL and its affiliates must comply with this Order.

B. <u>FPSC Rule</u>

The Florida Public Service Commission has adopted rules concerning cost allocation and affiliate transactions (Rule No. 25-6.1351). The purpose of this Rule is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and non-regulated utility activities so that these transactions and activities are not subsidized by utility ratepayers. The processes outlined in this cost allocation manual were developed to ensure compliance with this Rule.

C. <u>NARUC Guidelines</u>

The National Association of Regulatory Utility Commissioners (NARUC) has developed a set of guidelines to assist regulated utilities and their affiliates in the development of procedures for recording transactions for services and products between a regulated entity and its affiliates. The prevailing premise of these guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities. The processes outlined in this manual are in accordance with these guidelines, as described in Exhibit A.

D. <u>Diversification Report</u>

In addition to the FERC Form No. 1, Annual Report of Major Electric Utilities, Licenses and Others, FPSC Rule No. 25-6.1351 requires the Utility to file an Annual Diversification Report. This report contains:

- Summary of changes to the corporate structure
- Updated structure showing parent and affiliates
- Summary of new or amended contracts with affiliates
- All transactions between FPL and it’s regulated and non-regulated affiliates

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

- Detail reports of all individual transactions over $500,000 between FPL and affiliates
- Summary of asset transfers between FPL and affiliates
- Employee transfers between FPL and affiliates
- Analysis of non-tariffed services and products provided by the utility
- Description of certain activities recorded by the utility as miscellaneous income, deductions and interest

IV. BILLINGS TO AFFILIATES FOR SERVICES PROVIDED BY FPL

FPL supports enterprise and affiliate operations through direct project activities and shared governance, compliance and other support functions. Direct activities are charged to affiliates through specific WBS elements (see subsequent sections of this manual for process details). Shared support functions are allocated through the following mechanisms:

1. Corporate Services Charge (CSC)
2. Nuclear Operations Support Charge
3. Information Technology Support Charge

All services provided to affiliates, either direct or allocated, are billed at actual cost using fully loaded rates. Payroll is charged using the employee's actual payroll rate plus loaders, which cover payroll taxes, benefits, and administrative costs.

A. Corporate Services Charge (CSC) [(1)]

The Corporate Services Charge was implemented to bill Corporate Staff shared services and certain capitalized hardware and software benefiting both FPL and its affiliates. This charge is based on a cost pool of shared services, which is allocated based on specific drivers or the Massachusetts Formula.

Cost Pool – Corporate Shared Services

The Shared Services cost pool is determined annually through an extensive review of shared services and certain capitalized hardware and software provided by FPL's Corporate Staff Departments to entities across the enterprise. The review is performed in conjunction with FPL's budget cycle and identifies the products and services to be allocated based upon each Work Breakdown Structure (WBS). These budgeted costs are combined to obtain an estimated shared cost pool for the subsequent year.

[(1)] The CSC was formerly referred to as the Affiliate Management fee (AMF). The name was changed in 2016 to more accurately describe the costs.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

On a monthly basis, the affiliate entities are billed their share of the Corporate Services Charge using the drivers described below and the actual fully loaded costs (i.e., including all payroll overheads listed in the table below except for A&G and non-productive) incurred for the month by the FPL department providing the service. Specifically, the amount of the charge is determined by multiplying the actual shared costs incurred (accumulated in SAP each month by WBS) by the appropriate driver percentages. The resulting allocations are then billed to the affiliates via the SAP settlement process as an inter-company charge.

Shared Services Allocated via Specific Drivers

The list below includes the functional areas of support, along with examples of shared services that are provided by FPL to benefit the entire enterprise. These services are included in the Corporate Services Charge and are allocated to affiliates via the use of specific drivers.

- **Finance** (Specific drivers based on transactions)
  - Corporate Transactions – Accounts Payable, Miscellaneous Accounts Receivable

- **Information Technology** (Specific drivers based on workstations, mainframe time, cell phone users, etc.)
  - Corporate Applications – HR Employee Information System, Procurement, Financial Data Base, Email Systems
  - Communications & Technology – Telecommunications and Network Operating Centers (NOC), Corporate Cellular Phones
  - Cyber Security
  - Distributed Systems – Workstation, LAN and WAN Support
  - Mainframe Operations – Computer Centers at Corporate Locations
  - PC Services – Help Desk and Workstation Support
  - Amortization and ROI – Shared Capitalized Hardware and Software

- **Human Resources/Corporate Real Estate/Security** (Specific drivers based on FTE's and square footage)
  - Employee Relations – Safety Polices, Labor Relations Administration, and other employee related issues
  - Shared Services – Benefits Administration, Employee Support Line, Payroll Administration, Educational Assistance, Recruiting, Equal Opportunity and Diversity, Workforce Planning, Drug Testing and Group University
  - Benefit Programs
  - Health Centers
  - Cafeteria Operations – Shared Affiliate Cafeteria Operations for applicable sites (JB, GO, LFO, CSE, PTN & PSL)
  - Security Administration – Facility Security, Data Security

- **Corporate Development** (Specific drivers based on headcount)
  - Six Sigma and Strategic Quality Projects

- **Business Unit Leadership**
  - Power Generation Division (drivers based on megawatts)
  - Nuclear Division (drivers based on number of operating units)

Shared Services Allocated via the Massachusetts Formula

For the allocation of the cost pool(s) where there were no specific driver(s), FPL utilizes the average of Payroll, Revenues, and Gross Property, Plant and Equipment to allocate shared costs between FPL and benefitting affiliates. This methodology is commonly referred to as the "Massachusetts Formula" and has been an industry standard for rate regulated allocations. The forecasted amounts for each of the three components are estimated for all applicable entities and given equal weight. An average is then computed for each operating entity, which when compared to the total, yields a ratio used to allocate its share of the cost pool. Below are examples of the services that are included in the CSC and allocated using the Massachusetts Formula.

- **Executive and Governance**
  - Salaries, benefits and expenses
- **Finance**
  - Accounting – Cost Measurement & Allocation, Accounting Research & Financial Reporting
  - Corporate Tax
  - Treasury & Investor Relations
  - Trust Fund Investments
  - Risk Management

- **Corporate Communications**
  - Internal Communications
  - External Media
  - Annual Report

- **General Counsel/Environmental/Compliance**
  - Board of Directors Fees
  - FERC & NERC Compliance
  - Ethics
  - General Counsel Administration
  - Environmental Services

- **Engineering and Construction**
  - Integrated Supply Chain – Administration of Corporate Travel and Integrated Supply Chain

- **Human Resources/Corporate Real Estate/Security**
  - Mail Services – Courier and Mail Services (GO, JB, LFO)
  - Security Operations Center

- **Internal Audit**
  - Internal Audit Management

- **Corporate Operational Development**
  - Process Improvement Initiatives

Allocation of Costs for Significant Capital Projects

For significant capital projects which will benefit the enterprise and/or FPL and certain affiliates (typically software development projects), the business case developed in support of the project will identify future expected benefits to each of the entities that will be utilizing the system or application. For these projects, an analysis should be performed during the planning phase to determine the appropriate sharing of costs and each benefitting entity should record their respective share of the capital project. Post implementation, on-going maintenance activity costs are included in the CSC as described in the Information Technology paragraph under the Corporate Services Charge section above.

B. Nuclear Operations Support Charges–Nuclear (NUC), IT Nuclear (ITNUC) [(2)]

Nuclear Operations Support Charges are utilized to bill shared nuclear fleet services. FPL has leveraged its fleet construction, compliance and operating capabilities over the broader enterprise for many years in order to optimize results for its customers. The larger scale of the enterprise fleet has historically allowed for shared expertise and the resulting competitive advantage. Operations Support Charges are managed by the Business Unit (Nuclear or Information Technology) Budget Coordinators and represent ongoing services provided or shared among affiliates. The Nuclear Operations Support Charges includes fleet support to NextEra Energy, Inc. (FPL and NextEra Energy Resources) nuclear plants, and specific system support for NextEra Energy Resources nuclear plants.

The Nuclear Operations Support Charges include all overheads reflected in the table below except for the non-productive loader because full salaries are allocated based on relevant drivers to each entity served.

Nuclear Fleet Operations Support Charge

The Nuclear Fleet Operations Support Charge is billed using actual monthly charges that are accumulated and then allocated using the number of generating units as the driver. The Nuclear Operations Support Charge includes the following shared services:

- Nuclear Engineering
- Nuclear Assurance

[(2)] The Nuclear Operations Support Charges were formerly referred to as Service Fees. The name was changed in 2016 to more accurately describe the costs.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

- Nuclear Business Operations
- Nuclear Security Access
- Nuclear Security
- Nuclear Licensing and Regulatory Support
- Nuclear Performance Improvement
- Nuclear Fuel Engineering
- Nuclear Training

Specific project related services not included in the Nuclear Fleet Operations Charge, which are direct charged to NextEra Energy Resources by FPL Nuclear, are:

- Due Diligence
- Construction Projects
- Transition Teams
- Support of NextEra Energy Resources Capital Projects
- Outage Support
- Nuclear Project Controls (Cost tracking of projects)

Nuclear Information Technology Operations Support Charge

The Nuclear Information Technology Operations Support Charge is also billed using actual monthly charges that are accumulated and then allocated based on the number of generating units. The Information Technology Nuclear Support Charge includes the following shared services:

- Nuclear Asset Management System (NAMS) Support
- IM Management
- Data Services
- IMO Nuclear Lead (Infrastructure Support)
- Nuclear Web Applications Support

C. <u>Inter-Company Direct Billing</u>

In accordance with FERC and FPSC requirements, FPL bills affiliates its fully loaded cost for services provided, using specific WBS elements obtained via the following process:

1. Affiliate Project Manager requests FPL employee services

The affiliate project manager contacts the FPL employee’s supervisor and requests the services of the employee on a project for a specific amount of time or thru completion of a job.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

2. Project Manager Provides FPL with a Work Breakdown Structure (WBS) for Billing

After obtaining approval by the supervisor, the Project Manager requesting the service must provide a WBS element for the FPL employee to charge.

- It is the responsibility of the supervisor to ensure that the correct Overhead Key for affiliate transactions is applied to the WBS.

3. FPL Employee charges appropriate WBS element on the timesheet for specific hours worked

Charges to the WBS elements are accumulated each month and loaded with the appropriate overheads during the SAP settlement process which is executed several times during the month. Also included in the billable charges are any appropriate non-payroll charges. See Exhibit B for a list of FPL's payroll and non-payroll overhead rates.

It is the responsibility of the employee to ensure that any work performed for affiliates is properly recorded in his/her timesheet. It is the responsibility of each employee's supervisor to ensure that all time sheets are reviewed in accordance with FPL's Sarbanes –Oxley processes to ensure that all affiliates are properly charged.

D. <u>Transfer of Assets From FPL to Affiliates</u>

In addition to services provided, FPL may transfer assets used in its regulated operations to an affiliate. In accordance with FPSC and FERC requirements, FPL will charge the non-regulated affiliate the greater of market price or net book value. It is the responsibility of the Investment Recovery Operations group to ensure that market testing is performed and that proper documentation is maintained. As required per the FPSC affiliate Rule, an independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. On certain occasions, FPL may transfer the asset at either market price or net book value if it maintains documentation to support and justify that such a transaction benefits regulated operations. When these billings occur, notification must be given to FPL Regulatory Accounting to ensure proper reporting of these transactions as required by FERC and FPSC.

E. Overhead Rates

FPL attaches various overhead rates to payroll charged to affiliates to ensure that all relevant indirect costs associated with each employee are appropriately billed. Overhead rates and the purposes of each are described below:

Rate Description	Rate Purpose	Rate Application	Basis for Calculation
Funded Welfare **Unfunded Service** **Unfunded Benefits**	Pension & Welfare recovers company dollars budgeted for current year for expenses related to life, medical & dental insurance, thrift plan and long term disability benefits. Also recovers pension, retiree medical, employee education assistance and benefit costs.	CSC Nuclear Operations Support Charge Inter-Company Direct Charges	Based on Forecasted Data Calculated Annually During the Budget Cycle
Payroll Tax OH FICA (Social Security & Medicare) FUTA (Federal Unemployment Insurance) SUTA (State Unemployment Insurance)	Recovers estimated company payments for social security, Medicare, state & federal unemployment and workers compensation insurance.		
Performance Incentives - Exempt	Recovers the cost of the budgeted performance incentive for exempt employees.		
Workers Comp	Recovers estimated payments for workers comp insurance.		
Non-Productive	Recovers the cost of non-productive time such as vacation, sick time and other non-excused absences plus non-distributed other earnings such as relieving time, shift differential and merit pay. Distribution, Transmission and Substation non-productive is applied to bargaining variable direct labor only.	Nuclear Operations Support Charge Inter-Company Direct Charges	Based on Historical Data Calculated Annually during Q1
A&G Payroll	Recovers the O&M payroll of corporate and business unit staff support	Inter-Company Direct Charges	
A&G Expenses	Recovers the O&M expenses of corporate and business unit staff support		

See Exhibit B for a list of rates effective January 2025.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

Long Term Assignment Rates:

When FPL employees are used exclusively for affiliate activities for extended periods of time, a reduced Long-Term Loading Rate should be used. This is due to two factors. First, non-productive time (sick, vacation, holiday) is already included in the salary being billed since it is expected that a full year's salary is billed. If non-productive time were also loaded, the affiliate would be charged twice. Secondly, and as long the affiliate will be providing the necessary A&G support, such as supervision, office equipment, supplies, etc., the FPL A&G expenses should not be included in the loading rate.

To qualify for reduced loading, the employee must reasonably expect to charge their time to an affiliate WBS for one full year and be physically located at the affiliate's office. If an employee's charges during the year fall below 75%, they must be removed from the long-term loading rate.

Employees meeting the above requirements must charge a specific WBS element that has been set up with the long term overhead key. "Z604: Long-Term No External Overheads". These WBS elements will receive payroll taxes and benefits for affiliate support, but no external overheads. Once the employee's charges fall below 75%, they must charge a WBS element that has been set up to include the external overheads.

If an employee is expected to provide more than 50% of their time in support of another entity indefinitely, then the employee should be re-badged to that entity.

F. FACILITY AND EQUIPMENT CHARGES

FPL Regulatory Accounting is responsible for monthly entries to bill the following activities:

Systems Charges:
A small number of affiliates utilize various FPL systems on a limited basis for printing, mailing and payment processing of various items. These systems include the SAP and Payment Processing Center (PPC) systems. The use of these systems is billed on a transactional basis. A cost study is performed by the Customer Service organization in conjunction with the Cost Measurement and Allocation department to determine the cost to FPL per transaction for these systems. The number of transactions is collected monthly and billed to the affiliates at those rates.

Furniture and Computers:
Affiliates are billed monthly for office furniture using a weighted average rate that includes the cost for fully depreciated furniture for which no market exists, and market value for new furniture.

Office Space:
Space is available to the affiliates in FPL buildings only when vacancies exist. The non-regulated affiliates are charged for the square feet they occupy based on the higher of cost or a market rate, which is updated every five years based on a market study performed by Corporate Real Estate (CRE). Regulated affiliates are billed based on cost. A market rate analysis is performed periodically by Corporate Real Estate and was last prepared in 2022.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

V. BILLINGS TO FPL FOR SERVICES PROVIDED BY AFFILIATES

Limited shared services are provided by affiliate personnel. When FPL requests specific project support from an affiliate, the affiliate bills FPL for time spent, using actual costs that are loaded with all affiliate payroll and non-payroll overheads (see Section V-B below). In addition to specific project support, NEER's Information Technology group provides support to the Nuclear Fleet. The fleet support is billed using actual costs that are allocated based on number of generating units. FPL Regulatory Accounting group reviews the driver calculations on an annual basis.

A. Transfer of Assets to FPL from Affiliates

As required by FPSC and FERC rules, billings from affiliates to FPL for assets transferred are based on the lower of cost or market. It is the responsibility of the Investment Recovery Operations group to ensure that market testing is performed, and that proper documentation is maintained. Per the FPSC Affiliate Rule, an independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. On certain occasions, FPL may record the asset at either market price or net book value if it maintains documentation to support and justify that such a transaction benefits regulated operations. When these billings occur, notification must be given to FPL Regulatory Accounting to ensure proper reporting of these transactions as required by FERC and FPSC.

B. Affiliate Overhead Rates

The calculation and maintenance of the overhead rates applied to direct charges coming into FPL are the responsibility of the affiliate performing the services. On an annual basis (typically at the end of Q1), FPL Regulatory Accounting requests, from applicable affiliates, the rates that will be used in the upcoming year, along with email confirmation that the rates have been properly updated in SAP.

C. Affiliate Procurement of Goods under Vendors Common with FPL

When affiliates procure goods from common vendors of FPL, they should do so directly under separate affiliate purchase orders. This ensures invoicing and product delivery will be processed directly to the appropriate entity, and FPL's affiliates will not be billed for FPL's loading costs. It also ensures that the contract terms (warranties and liabilities) of the purchase order(s) are placed with the affiliate, not with FPL. In some cases, the affiliate has the ability to take advantage of master agreements established between FPL and the vendor. FPL's strategy is to evaluate fleet wide (multi-site) agreements category by category with a focus on total value for FPL and supplier quality, taking advantage of leverage opportunities to consolidate the spend across the entire fleet, establish long term contracts with a limited number of suppliers of proven experience and quality, and to negotiate terms that provide for shared risks and shared benefits for improved performance.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

VI. ACTIVITIES BETWEEN REGULATED ENTITIES

FPL has several regulated affiliates that must also abide by affiliate transaction rules in order to protect their own ratepayers. Regulated affiliates of FPL currently include LoneStar Transmission, New Hampshire Transmission, TransBay Cable, Horizon West Transmission, NextEra Energy Transmission New York, Gridliance Management Company, Gridliance Heartland, Gridliance West, Gridliance HighPlains and NextEra Energy Mid-Atlantic. All activities between FPL and its regulated entities should be transacted at fully loaded cost.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

VII. DEFINITIONS

Affiliates – Companies that are related to each other due to common ownership or control.

Cost Allocators – The methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

Common Costs – Cost associated with services or products that are of joint benefit to both regulated and non–regulated business units.

Cost Driver – A measurable event or quantity which influences the level of costs incurred and which can be directly traced to an origin of the costs themselves.

Fully Allocated – Services or products bear the sum of the cost drivers plus an appropriate share of the indirect costs.

Non-regulated – Refers to services or products not subject to regulation by regulatory authorities.

Prevailing Market Rate – A generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

Regulated – Refers to utility services or products subject to rate regulation by regulatory authorities.

Subsidization – The recovery of costs from one class of customers, business unit or entity, that are attributable to another.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

Exhibit A – NARUC Guidelines for Cost Allocations and Affiliate Transactions

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

Exhibit B – 2025 Overhead Loading Rates

Overhead Rates Applied to Direct Charges

Non-productive payroll	16.24%
Performance Incentive	18.02%
Pension and Welfare	6.77%
Administrative and General Payroll	4.61%
Administrative and General Expense	9.58%
Payroll Taxes	Varies by Month
Workers Compensation Insurance	Varies by BU

Overhead Rates Applied to the Nuclear Operations Support Charges

Performance Incentive	18.02%
Pension and Welfare	6.77%
Administrative and General Payroll	4.61%
Administrative and General Expense	9.58%
Payroll Taxes	Varies by Month
Workers Compensation Insurance	Varies by BU

Overhead Rates Applied to Shared Services Payroll Dollars Included in the CSC

Performance Incentive	18.02%
Pension and Welfare	6.77%
Payroll Taxes	Varies by Month
Workers Compensation Insurance	Varies by BU

FLORIDA POWER & LIGHT COMPANY
FPL Regulatory Accounting
Cost Allocation Manual (CAM)
2025

Regulatory Accounting
Cost Allocation Manual (CAM)
Exhibit C - 2025 MASS FORMULA RATIOS AND SPECIFIC DRIVERS

Description	FPL	NEER	FPLES	NEECH/NEE	NHT	LST	NEET	Florida City Gas	TransBay Cable	Horizon West Trans	GridM	GridW	GridHP	GridH	NEETNY	NEETMA	Total Affiliate %
MASS FORMULA RATIOS																	
MF-Shared	57.41%	38.48%	0.51%	1.63%	0.09%	0.47%	0.21%	0.00%	0.38%	0.08%	0.03%	0.27%	0.08%	0.04%	0.25%	0.06%	42.59%
SPECIFIC DRIVERS																	
Headcount	54.43%	42.39%	1.35%	0.16%	0.00%	0.20%	1.16%	0.00%	0.08%	0.00%	0.24%	0.00%	0.00%	0.00%	0.00%	0.00%	45.57%
Square Footage - All sites	81.10%	15.65%	1.17%	1.28%	0.00%	0.05%	0.76%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	18.90%
Square Footage - Juno Beach Office	42.97%	46.34%	3.37%	4.86%	0.00%	0.04%	2.43%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	57.03%
Capitalized Hardware/Software shared with Affiliates	67.86%	29.40%	1.46%	0.00%	0.00%	0.32%	0.45%	0.00%	0.33%	0.00%	0.18%	0.00%	0.00%	0.00%	0.00%	0.00%	32.14%
Number of Operating Units - NUC Executive	57.14%	42.86%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	42.86%
Affiliate Megawatts - PGD Executive	45.03%	54.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	54.97%
Actual number of workstations per Business Unit for support and project activities	60.59%	36.55%	1.44%	0.00%	0.00%	0.22%	0.84%	0.00%	0.19%	0.00%	0.17%	0.00%	0.00%	0.00%	0.00%	0.00%	39.41%
Actual number of workstations per Business Unit (includes Affiliates in FPL/Florida facilities) for support and project activities	77.28%	20.66%	1.13%	0.00%	0.00%	0.05%	0.82%	0.00%	0.00%	0.00%	0.06%	0.00%	0.00%	0.00%	0.00%	0.00%	22.72%
IT resources for transmission systems supporting Affiliates	92.84%	4.50%	0.00%	0.00%	0.00%	2.66%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	7.16%
Servers per Business Unit / Affiliate for support and project activities	72.30%	25.31%	0.27%	0.00%	0.00%	0.99%	0.00%	0.00%	1.13%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	27.70%
Database Administrator Resource - Business Intelligence Data Movement	97.14%	2.86%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.86%
Database Administrator Resource - Technical Support	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
SAP User count per Business Unit / Affiliate for support and project activities	59.04%	37.53%	1.65%	0.00%	0.00%	0.28%	0.70%	0.00%	0.22%	0.00%	0.58%	0.00%	0.00%	0.00%	0.00%	0.00%	40.96%

**Services in support of NextEra Energy Partners are charged to NEER using a Mass Formula rate of 42.08%*

Affiliate Charges Based on Billing Methodology

2026 Projected Test Year