BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20210015-EI

Petition for rate increase by Florida Power & Light Company.
___________________________/

VOLUME 4
PAGES 735 - 970

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING: CHAIRMAN GARY F. CLARK
COMMISSIONER ART GRAHAM
COMMISSIONER ANDREW GILES FAY
COMMISSIONER MIKE LA ROSA
COMMISSIONER GABRIELLA PASSIDOMO

DATE: Monday, September 20, 2021

TIME: Commenced: 9:30 a.m.
Concluded: 12:00 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: DEBRA R. KRICK
Court Reporter

APPEARANCES: (As heretofore noted.)

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I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 3.)

(Whereupon, prefiled direct testimony of Keith Ferguson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KEITH FERGUSON

DOCKET NO. 20210015-EI

MARCH 12, 2021

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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. I am responsible for ensuring that the Company's financial reporting complies with requirements of Generally Accepted Accounting Principles ("GAAP") and multi-jurisdictional regulatory accounting requirements. As a part of these responsibilities, I work directly with the asset recovery team responsible for analyzing and recording the depreciation, dismantlement, and nuclear decommissioning expenses for FPL and I am involved in preparing the periodic studies related to these topics.

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 their energy audit practice in Atlanta, Georgia. From 2002 to 2005, I worked for Deloitte & Touche in their 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. When I joined FPL in 2011, I was the Assistant Controller for FPL and responsible for overseeing FPL's property and general accounting functions. 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:

- KF-1 Consolidated MFRs Sponsored or Co-sponsored by Keith Ferguson
- KF-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-sponsored by Keith Ferguson
- KF-3(A) Impacts to Depreciation Expense using 2021 Depreciation Study Depreciation Rates by Year for Base vs. Clause for 2022 and 2023
- KF-4 Summary of Capital Recovery Schedules for 2022 and 2023 – Base Rates vs. Clause
- KF-5 Proposed Dismantlement Company Adjustments for Base vs. Clause

- KF-6 Proposed Company Adjustments for Change in Nuclear End of Life Accruals
- KF-7 2021 Cost Allocation Manual
- KF-8 Affiliate Charges Based on Billing Methodology for the 2022 Test Year

I am co-sponsoring the following exhibits:

- KF-3(B) Proposed Depreciation Company Adjustments by Year for Base vs. Clause for 2022 and 2023 using the RSAM Adjusted Depreciation Rates
- JTK-1 2021 Dismantlement Study, filed with the direct testimony of FPL witness Kopp
- REB-11 Reserve Surplus Amortization Mechanism, filed with the direct testimony of FPL witness Barrett
- TCC-9 Rates for FPL and Gulf as Separate Ratemaking Entities, filed with the direct testimony of FPL witness Cohen.

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. Yes. Exhibit KF-1 lists the consolidated MFRs I am co-sponsoring.

Q. Are you co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. Yes. Exhibit KF-2 lists the supplemental FPL and Gulf Power ("Gulf") standalone information in MFR format that I am co-sponsoring.

Q. What time periods are presented in the referenced MFRs and schedules?

A. The referenced consolidated MFRs and FPL and Gulf standalone schedules reflect information for the 2020 Historical Test Year, 2021 Prior Year, 2022 Test Year, and 2023 Subsequent Year.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. Operations and time periods after January 1, 2022 are referred to as FPL because Gulf will be consolidated into FPL. Therefore, unless otherwise noted, my testimony and references to FPL address the consolidated Company.

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 "2021 Depreciation Study"), which was conducted in accordance with the rules and requirements of the Florida Public Service Commission ("FPSC" or the "Commission"). The 2021 Depreciation Study has been prepared by FPL witness Allis of Gannett Fleming and is supported in his direct testimony in this docket. I also provide the Reserve Surplus Amortization Mechanism ("RSAM") adjusted depreciation rate impacts to depreciation expense that are discussed in more detail later in my testimony;
- 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 adjustments as a result of FPL's dismantlement study (the "2021 Dismantlement Study"), which was conducted in accordance with the rules and requirements of the Commission. The 2021 Dismantlement Study has been prepared by FPL witness Kopp of 1898 & Co., a division of Burns & McDonnell, a global engineering consulting firm that specializes in preparing dismantlement studies for electric utilities, and is supported in his direct testimony in this docket;
- I support the change in FPL's end of life materials and supplies ("EOL M&S") and nuclear fuel last core accruals as presented in FPL's most recent nuclear decommissioning study filed in December 2020 (the "2020 Nuclear Decommissioning Study");
- I provide testimony and information on various affiliate issues.

Q. Please summarize your testimony.

A. The 2021 Depreciation Study reflects a modest decrease in 2022 and a modest increase in 2023 in depreciation accruals primarily as a result of lower depreciation rates in nuclear as a result of the Turkey Point subsequent license extension, even taking into account depreciation rates for transmission and distribution that are higher than those approved in the 2016 Settlement.

As described in witness Barrett's testimony, in this proceeding FPL is requesting approval of an RSAM like the one that the Commission approved most recently in FPL's 2016 Settlement and my testimony presents the impacts of several depreciation adjustments that the Commission could approve in lieu of those presented in FPL witness Allis' 2021 Depreciation Study should the Commission allow FPL to continue to use the RSAM.

FPL has retired 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 ten-year period.

FPL, as required by the FPSC, has established and maintained a dismantlement reserve for its non-nuclear generating units. In accordance with Rule 25-6.0436, FPL has updated its cost estimates and revised its annual accrual accordingly. The increase in the revised annual accrual primarily reflects new solar plants that have been or will be constructed since the 2016 Dismantlement Study was prepared.

FPL also has updated the calculation of its EOL M&S and nuclear fuel last core accruals based on information provided by FPL's nuclear decommissioning study filed in December 2020.

All of the above items are included as Company adjustments in FPL's 2022 Test Year and 2023 Subsequent 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 2016 rate case and remain fully consistent with Commission requirements.

II. 2021 DEPRECIATION STUDY

Q. Please summarize the impact of the 2021 Depreciation Study on FPL's 2022 Test Year and 2023 Subsequent Year.

A. Since its last depreciation study in 2016, FPL has worked closely with its depreciation consultant, Gannett Fleming, to incorporate updated technical data into the 2021 Depreciation Study. FPL witness Allis of Gannett Fleming presents the results of the 2021 Depreciation Study. The 2021 Depreciation Study reflects combined rates for FPL and Gulf as well as views for each utility as separate ratemaking entities. Rate calculations utilized the same lives and net salvage by FERC account for both FPL and Gulf for similar assets. The 2021 Depreciation Study reflects a modest decrease in depreciation accruals primarily as a result of the Turkey Point Nuclear Plant subsequent license renewal received in December 2019 as described in FPL witness Coffey's testimony, which is largely offset by an increase in depreciation accruals in the transmission and distribution functions.

The total decrease in depreciation expense for the 2022 Test Year as a result of the 2021 Depreciation Study is $1 million, which includes a $4 million decrease related to base rate assets and an offsetting $3 million increase related to cost recovery clauses. The $4 million decrease is primarily a result of the following:

- $107 million decrease in the nuclear function primarily as a result of the Turkey Point Nuclear Plant subsequent license extension which resulted in a 20-year increase in the useful life of the plant;
- $18 million decrease in the other production function as a result of longer lives in energy storage; which is largely offset by
- $123 million increase in the transmission and distribution functions as a result of an increase in depreciation rates from FPL's 2016 Rate Settlement that have been the foundation of the last multi-year base rate plan approved by the Commission.

For the 2023 Subsequent Year, there is an increase of $11 million in depreciation expense as a result of the 2021 Depreciation Study, of which $5 million relates to base rate assets and $6 million relates to cost recovery clauses. The same primary drivers apply to the $5 million increase in 2023 Subsequent Year with a $132 million increase in the transmission and distribution functions, largely offset by a $109 million decrease in the nuclear function and a $15 million decrease in other production. 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 2021 Depreciation Study?

A. The parameters utilized in the 2021 Depreciation Study are based in part on the statistical analyses of actual plant and reserve balance activity through December 31, 2019, which incorporates data through the most recent full year of historical data (e.g., retirements, net salvage, 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 2021, which includes actual balances as of September 30, 2020, to determine the appropriate depreciation rates. As FPL is using forecasted data for the 2022 Test Year and 2023 Subsequent Year, FPL appropriately included new assets that are not yet in service, such as the combustion turbines ("CTs") at the Gulf Clean Energy Center (formerly known as Plant Crist), Manatee Energy Storage, and numerous new 74.5 MW solar facilities, all of which are scheduled to be in-service by the end of 2021.

Q. How were the depreciation rates for generating plants expected to be placed in service after December 31, 2021 reflected in the rate case forecast and the depreciation Company adjustment?

A. FPL utilized proxy depreciation rates for the generating plants expected to be placed in service during the 2022 Test Year and 2023 Subsequent Year. For the Dania Beach Clean Energy Center ("Dania Beach"), FPL used the current approved depreciation rates and proposed depreciation rates for the Okeechobee Clean Energy Center ("OCEC") in the 2021 Depreciation Study as a proxy because OCEC is FPL's newest, most comparable combined cycle plant; hence it is most representative of the design and operating characteristics for the new Dania Beach plant. FPL also utilized the current approved depreciation rates and proposed depreciation rates for its 2021 solar plants as a proxy for the solar generating plants expected to be placed in service in 2022 and 2023.

Q. Has the Company calculated the impact to depreciation expense using the new depreciation rates from the 2021 Depreciation Study on the 2022 Test Year and 2023 Subsequent Year?

A. Yes. The depreciation expense Company adjustment reflects the impact of the difference in the rates from the 2021 Depreciation Study as compared to the currently approved depreciation rates. The current approved depreciation rates from Exhibit D of FPL's 2016 Rate Settlement were used to prepare the forecast for the 2022 Test Year and 2023 Subsequent Year. These depreciation rates are different than the rates resulting from the 2021 Depreciation Study. Accordingly, FPL has calculated the impact to the 2022 Test Year and 2023 Subsequent Year to reflect changes in base depreciation expense and accumulated depreciation based on the resulting depreciation rates in the 2021 Depreciation Study. The reconciliation of total company depreciation expense included in FPL's 2022 Test Year and 2023 Subsequent Year forecasts to the calculated expense based on the 2021 Depreciation Study are reflected on Exhibit KF-3(A).

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

A. No. Because some of FPL's investments are recovered through its Environmental Cost Recovery Clause ("ECRC"), Energy Conservation Cost Recovery Clause, Capacity Cost Recovery Clause and the Storm Protection Plan Cost Recovery Clause, the impact to base rate revenue requirements for the 2022 Test Year and 2023 Subsequent Year must exclude the amount of depreciation related to clause-recovered investment and include only the depreciation for investments recovered through base rates. Exhibit KF-3(A) reflects the total depreciation expense increase using the 2021 Depreciation Study rates and delineates between base rates and clause recovery. FPL will reflect the depreciation rate changes approved from this proceeding when it determines actual depreciation expense in the applicable clauses beginning in January 1, 2022, which is the date when the approved depreciation rates become effective.

Q. **Has FPL calculated the impact to depreciation expense resulting from the 2021 Depreciation Study for FPL and Gulf as separate ratemaking entities for 2022 and 2023?**

A. Yes. I provide the calculation of the impact to depreciation expense using the depreciation rates resulting from the 2021 Depreciation Study by year for base vs. clause for 2022 and 2023 for FPL and Gulf as separate ratemaking entities on Pages 2 and 3, respectively, of Exhibit KF-3(A).

Q. Please describe the RSAM adjusted depreciation rates that you discussed in the summary of your testimony.

A. As FPL witness Barrett discusses in detail in his direct testimony, FPL is requesting approval to continue use of the RSAM. In order to facilitate this request, I asked FPL witness Allis to calculate several alternative depreciation parameters that the Commission could approve in lieu of those presented in the 2021 Depreciation Study to enable continued use of the RSAM and the Company's four-year rate plan. In summary, the RSAM adjusted depreciation rates consist of the following adjustments relative to the 2021 Depreciation Study:

- An increase in plant life from 60 years to 80 years for the St. Lucie Nuclear Plant based on the expectation that FPL receives a subsequent license renewal;
- Increase in combined cycle generating plant lives from 40 years to 50 years;
- Increase in solar generating plant lives from 30 years to 35 years; and
- For Transmission, Distribution and General Plant functions: adopting the lives and/or net salvage from either the 2016 FPL Rate Settlement or FPL witness Allis' 2021 Depreciation Study, whichever results in longer lives and/or higher net salvage.

A summary of these alternative depreciation parameters, along with a reference to where they appear in the exhibits of FPL witness Allis, are provided on pages 3 through 24 of Exhibit KF-3(B).

Q. What is the basis for the RSAM adjusted depreciation rates related to production plant?

A. The St. Lucie Nuclear Plant subsequent license renewal is expected to be filed with the Nuclear Regulatory Commission ("NRC") in August 2021 as discussed in FPL witness Coffey's testimony. Typically, the Company would wait until the license extension is issued by the NRC to reflect the useful life change in depreciation rates. However, given the level of confidence that the license renewal will be obtained and to facilitate the continued use of the RSAM, it would be reasonable to incorporate the extended life into the depreciation rates that support the four-year rate plan.

The Company currently expects to operate its combined cycle facilities for 40 years as proposed by FPL witness Allis. However, as described by FPL witness Broad, the Company has made significant investments in these facilities in recent years that upgraded much of the primary components of the plants, and these investments can increase the useful lives of these plants. We are aware of at least one non-FPL combined cycle plant owned by Public Service of Oklahoma, the Comanche plant, that is nearing 50 years in service. Based on FPL's record of performance and its upgrades to these plants, along with the potential to convert these plants to utilize green hydrogen as a fuel source similar to the pilot described by FPL witness Valle, these plants may be able to be operated up to 50 years. Thus, in support of the continued use of RSAM and the four-year rate plan, it would be reasonable to incorporate the extended life into the determination of FPL's depreciation rates.

The estimated 30-year useful life for solar generating plants in FPL's 2021 Depreciation Study is consistent with the Company's 2016 Depreciation Study. However, for purposes of supporting the RSAM and the four-year rate plan, it would be reasonable for the Commission to consider a recent survey of solar industry professionals conducted by the Department of Energy[1] which indicated that there has been an increase in recent years in the useful life of solar generating plants with some industry experts now suggesting that a 35-year life is feasible. Thus, use of a 35-year life would be reasonable to support the continued used of RSAM and the four-year rate plan.

Q. Is FPL asking the Commission to ignore the 2021 Depreciation Study that FPL witness Allis prepared?

A. No. The 2021 Depreciation Study is sound, reasonable and accurate, and should be approved as such along with the associated adjustments to base revenue requirements for 2022 and 2023 if the Commission does not approve the continued use of the RSAM that FPL witness Barrett discusses in his testimony. If, however, the Commission approves the continued use of the RSAM as a means of achieving the policy objectives that FPL witness Barrett discusses,

[1] https://eta-publications.lbl.gov/sites/default/files/solar_life_and_opex_report.pdf

then recognizing that there are differences both in the estimated and actual lives of plant, opting to make certain longer-lived assumptions in favor of enabling longer term rate stability is a reasonable outcome and the RSAM-adjusted depreciation rates should be approved in lieu of the 2021 Depreciation Study depreciation rates.

Q. Has FPL calculated Company adjustments to base depreciation expense using RSAM adjusted depreciation rates for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. As reflected on Exhibit KF-3(B) Page 1, I provide the proposed depreciation Company adjustments using the RSAM adjusted depreciation rates by year for base vs. clause for 2022 and 2023. The resulting decrease to base depreciation expense for the 2022 Test Year and 2023 Subsequent Year is $239 million and $249 million, respectively, and are included in the calculation of revenue requirements sponsored by FPL witness Fuentes. This represents significant revenue requirement reductions for the 2022 Test Year and 2023 Subsequent Year, compared to the necessary revenue requirements in the event the RSAM is not approved as part of the Company's requested four-year rate plan.

III. CAPITAL RECOVERY SCHEDULES

Q. Please describe the capital recovery schedules for assets retired but not fully depreciated.

A. As shown on Exhibit KF-4 and pursuant to Rule 25-6.0436, F.A.C., FPL has reflected its proposed capital recovery schedules, all of which are requested to be recovered over a 10-year period consistent with the capital recovery schedules approved in FPL's 2016 Rate Settlement. FPL is requesting recovery of the following unrecovered investments either through base rates or clause recovery, including:

- $365 million of remaining investment at Martin Units 1 & 2 which were retired in December 2018. In FPSC Order No. PSC-2019-0045-PAA-EI, the Commission approved the deferral and the establishment of a regulatory asset for recovery to be addressed in the next general base rate proceeding;
- $328 million of remaining investment at Lauderdale Units 4 & 5 which were retired in December 2018 as part of the construction associated with Dania Beach. In FPSC Order No. PSC-2019-0045-PAA-EI, the Commission approved the deferral and the establishment of a regulatory asset for recovery to be addressed in the next general base rate proceeding;
- $462 million of remaining investment specific to coal generation at the Gulf Clean Energy Center Units 4 – 7 which were retired in October

2020 as a result of the plant's conversion to natural gas. On March 2, 2021, the Commission voted to approve Gulf's request to create the base rate and ECRC regulatory assets in Docket Nos. 20200242-EI and 20200007-EI and defer the decision of the appropriate amount and recovery of the regulatory assets to a future date;

- $231 million of estimated remaining investment at Manatee Units 1 & 2 steam generating units which are expected to be retired in January 2022 with capital recovery beginning in February 2022;
- $112 million of estimated remaining investment for FPL's 500 kV Transmission System and related Cost of Removal ("COR") beginning in January 2022 and $92 million of estimated remaining investment and COR beginning in January 2023. FPL's 500 kV Transmission System will be retired as work is performed and the remaining unrecovered investment will be transferred to a regulatory asset in tranches on an annual basis. For example, the amount shown for 2022 amortization relates to the remaining unrecovered investment and COR expected as a result of retirements through 2021 and the 2023 amortization relates to unrecovered investment and COR as a result of retirements occurring in 2022; and
- $831 million of estimated remaining investment at Scherer Unit 4, a jointly-owned coal plant that is expected to be retired in January 2022 with capital recovery beginning in February 2022.

Q. Is the Company retiring other significant capital assets outside its 2022 Test Year and 2023 Subsequent Year?

A. Yes. FPL expects to retire the following assets during 2024 and 2025:

- $67 million in 2024 and $82 million in 2025 of estimated remaining investment and COR related to FPL's 500 kV Transmission System as described above; and
- $136 million in 2024 of estimated net book value at retirement related to Daniel Units 1 and 2, a jointly-owned coal plant that is expected to be retired in 2024.

Q. Please explain how the Company proposes to recover the remaining unrecovered investment related to the asset retirements currently scheduled for 2024 and 2025.

A. Because of the expected retirement dates, these units are excluded from the 2021 Depreciation Study. Once the retirements take place, the Company proposes the following treatment:

- 500 kV Transmission System: Establish a regulatory asset for the estimated remaining investment and COR for retirements taking place during 2024 and 2025 and commence its amortization upon retirement 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; and

- Daniel Units 1 and 2: Upon retirement, the Company proposes to reflect the estimated remaining investment as a negative amount (debit) in the accumulated reserve for the respective plant accounts. FPL will continue its depreciation for these retirements using current rates as approved in Gulf's 2017 Rate Settlement. The Company will address the establishment and amortization of a regulatory asset during its next base rate proceeding.

Q. Are the capital recovery schedules delineated between base rates and clause recovery?

A. Yes. Exhibit KF- 4 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 FPL's 2022 clause projection filing in August 2021 or thereafter depending on the retirement date. The resulting Company adjustment related to base rates for the 2022 Test Year and 2023 Subsequent Year are $117 million and $130 million, respectively, and are included in the calculation of revenue requirements sponsored by FPL witness Fuentes.

Q. Have the capital recovery schedules been prepared for FPL and Gulf as separate ratemaking entities?

A. Yes. Column 1 on pages 1 and 2 of Exhibit KF-4 identifies the retired units by entity.

IV. 2021 DISMANTLEMENT STUDY

Q. Please provide an overview of the approach FPL utilized for the preparation of its 2021 Dismantlement Study.

A. FPL engaged 1898 & Co., a division of Burns & McDonnell ("1898 & Co"), to perform the 2021 Dismantlement Study. 1898 & Co has performed dismantlement studies in numerous jurisdictions, including FPL's 2016 Dismantlement Study. 1898 & Co conducted a detailed bottom-up review of the fossil, solar, and certain battery storage units in FPL's and Gulf's fleet in order to get a more precise view of the current cost of dismantling those facilities on a combined basis and a view based on FPL and Gulf as separate ratemaking entities.

Since the 2016 Dismantlement Study, the Company has performed or will perform in the near future dismantlement activities at several generating units including Cedar Bay, Indiantown, Lauderdale Units 4 & 5, Manatee Units 1 & 2, Martin Units 1 & 2, Port Everglades gas turbine peakers, St. Johns River Power Park Units 1 & 2, Scholz Units 1 & 2, Smith Units 1 & 2, and Turkey Point Units 1 & 2. In addition, the Company has continued its ongoing closure activities associated with coal ash at the Gulf Clean Energy Center and Plants Daniel, Scherer, Scholz, and Smith. FPL also added new facilities to the generation fleet including new facilities resulting from the acquisition of Gulf and Indiantown, as well as the construction of Dania Beach, Gulf Clean Energy

Center CTs, and numerous solar facilities. The 2021 Dismantlement Study is covered in FPL witness Kopp's testimony and Exhibit JTK-1, which I co-sponsor.

Q. Please describe the process by which the 2021 Dismantlement Study was prepared.

A. As discussed further in FPL witness Kopp's testimony, 1898 & Co obtained and reviewed plant specific engineering drawings. Based on this information, their specific experience conducting the 2016 Dismantlement Study and their professional experience, 1898 & Co developed labor and materials and equipment costs for each major dismantlement activity. 1898 & Co 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 1898 & Co 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, Electric Utilities Dismantlement Studies, F.A.C.

In addition to the existing sites, 1898 & Co also developed estimates for FPL's new facilities that will commence commercial operation during 2021 through 2025, including a proxy estimate for solar generating plants where the specific locations were not yet determined at the time the study was prepared. This is consistent with the approach that FPL employed in its 2016 Dismantlement Study.

Q. In addition to the 2021 Dismantlement Study, did the Company factor in additional information in the calculation of the dismantlement accrual?

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

Q. Please describe the results of the 2021 Dismantlement Study and related accruals.

A. The 2021 Dismantlement Study calculated a current total cost of dismantlement of $1,178 million (expressed in 2021 dollars), including FPL's internal forecast estimates for dismantlement activities as reflected in Section 5.1 of Exhibit JTK-1. The resulting annual accrual is $53 million, of which $50 million relates to base rate assets. This is an increase of approximately $27 million ($24 million for the base rate portion), over the current annual accrual included in FPL's 2022 Test Year and 2023 Subsequent Year. The increase is primarily due to a $23 million increase related to plants that have been or will be constructed since the 2016 Dismantlement Study was prepared, as reflected in Section 2 of Exhibit JTK-1, most of which pertains to solar plants.

Q. Has FPL utilized the remaining dismantlement reserve amortization authorized in the 2016 Rate Settlement?

A. Yes. FPL expects to amortize all of the remaining $146 million of dismantlement reserve authorized in the 2016 Rate Settlement by December 31, 2021, and this has been reflected in the projected dismantlement reserve balance as of that date.

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. The resulting annual accrual is a function of the present value of estimated future cost to dismantle each of those units as compared to its forecasted reserve as of December 31, 2021. At any point in time, the reserve position of any particular unit will vary. Some units will have excess reserves and others will be in a deficit position.

As reflected on Exhibit KF-5, FPL has proposed transfers of reserve balances from the units that either had excess reserves or were the furthest from retirement to the units that are closest to retirement or are in the process of being dismantled. In doing so, FPL minimized the calculated incremental dismantlement accrual. As a result, FPL is proposing to transfer approximately $111 million of dismantlement reserve between the steam and other production functions and $15 million of dismantlement reserve between base and clause. The proposed transfers related to base rates are included as part of the dismantlement Company adjustment reflected on MFRs B-2 and C-3 for both the 2022 Test Year and 2023 Subsequent Year.

Q. What escalation rates did FPL utilize in preparing the 2021 Dismantlement Study accrual calculations?

A. FPL utilized the August 2020 Global Insight escalation rates in developing the 2021 Dismantlement Study accrual calculations.

Q. Is FPL proposing a Company adjustment to reflect the impact of the annual accruals from the 2021 Dismantlement Study on its 2022 Test Year and 2023 Subsequent Year?

A. Yes. As with depreciation, FPL utilized the current FPSC approved dismantlement accrual from its 2016 Dismantlement Study to prepare its 2022 Test Year and 2023 Subsequent Year forecasts and is proposing a Company adjustment to reflect the updated accrual contained in the 2021 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-5 provides an overview of the split between base and clause recovery for purposes of determining the Company adjustment for base rates for 2022 and 2023. The resulting Company adjustments related to base rates are included in the calculation of revenue requirements sponsored by FPL witness Fuentes.

Q. Has FPL calculated the dismantlement accrual Company adjustment for FPL and Gulf as separate ratemaking entities?

A. Yes. Pages 2 and 3 of Exhibit KF-5 provides an overview of the split of the requested dismantlement accrual between base and clause recovery for FPL and Gulf as separate ratemaking entities.

Q. Is FPL proposing any transfers from base to clause as part of the dismantlement Company adjustment?

A. Yes. In the 2016 Dismantlement Study, FPL included coal ash pond closure costs associated with its ownership interest in Scherer Unit 4 as a component of base rates. FPL believes that these costs are more appropriately recovered in the ECRC as they are being incurred to comply with the U.S. Environmental Protection Agency's Coal Combustion Residuals Rule, and the Commission has already approved a project for FPL to recover prudently-incurred costs for activities necessary to comply with this Rule in Order No. PSC-15-0536-FOF-EI. Accordingly, FPL is proposing certain Company adjustments to: (1) transfer the Scherer ash pond dismantlement reserve balance of $59 million as of January 1, 2022, and (2) transfer the proposed annual accrual of $9 million reflected on Exhibit KF-5 beginning on January 1, 2022 and its associated dismantlement reserve from base rates to the ECRC. These Company adjustments are included in the calculation of revenue requirements sponsored by FPL witness Fuentes.

V. END OF LIFE ACCRUALS FOR NUCLEAR FUEL LAST CORE AND MATERIALS AND SUPPLIES

Q. Does the 2020 Nuclear Decommissioning Study that FPL filed in Docket No. 20200257-EI propose revisions to the end of life accruals for FPL's nuclear plants?

A. Yes.

Q. Please describe those revised accruals.

A. In accordance with Rule 25-6.04365, F.A.C., Nuclear Decommissioning, FPL filed its nuclear decommissioning study on December 14, 2020. Using the same end of life assumptions utilized in that study, the nuclear decommissioning study updated FPL's estimates related to EOL M&S and nuclear fuel last core accruals. The revised annual accruals represent a decrease of $326 thousand for the EOL M&S and a decrease of $8 million for the nuclear fuel last core as a result of updates in the projected inventory balances at the time of decommissioning.

Q. Is FPL proposing a Company adjustment to reflect these revised annual accruals?

A. Yes. Although the Commission has not approved the 2020 Nuclear Decommissioning Study, FPL has reflected these two accrual changes as Company adjustments for the 2022 Test Year and 2023 Subsequent Year as shown in Exhibit KF-6. The resulting Company adjustments are included in the calculation of revenue requirements sponsored by FPL witness Fuentes.

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-7 contains FPL's 2021 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 last base rate filing in Docket No. 160021-EI?

A. No. FPL's current processes and billing practices continue to ensure that affiliate transactions comply with all applicable regulatory rules and regulations. FPL has further strengthened the control structure by centralizing certain functions, and continues to ensure that unregulated activities are not subsidized by regulated customers.

Q. Have there been any enhancements to FPL's shared services structure since the last base rate filing in Docket No. 160021-EI?

A. Yes. Since its last base rate filing, FPL has implemented various changes to its shared services structure that increase efficiencies and productivity, allowing FPL to achieve greater economies of scale. An example is the creation of the Finance Center of Excellence which centralized the transactional accounting (e.g., Corporate and Property Accounting) as well as Financial Planning and Analysis teams within NEE. The combination of these finance staff functions from across the organization streamlined processes and controls and eliminated duplication of some activities, all of which reduce the amount of costs ultimately borne by FPL and its customers.

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., Cost Allocations and Affiliate Transactions ("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 two 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 2021 CAM is included as Exhibit KF- 7.

Q. Have there been any changes since the last case to the billing methodologies that are utilized by FPL to charge costs to its affiliates?

A. No. FPL's existing methodologies continue to be effective in ensuring that all shared services are properly charged to the benefitting entities in the NEE organization. FPL continues to utilize 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. <u>Operations Support Charges</u> – Operations Support Charges are utilized by FPL to allocate support costs for NEE's Nuclear fleet support

operations, which provide services to both FPL and NEER's fleet of nuclear units. These charges are billed monthly, using the direct charge methodology, based on actual costs for the enterprise support activity.

3. Corporate Services Charges ("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 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-7 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.

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

A. As shown on Exhibit KF-8, approximately 76% of the support FPL forecasts it will provide to its affiliates in the 2022 Test Year will be billed using the direct charge method or allocated in the CSC using specific drivers. This is made up of approximately 39% using the direct charge methodology, 31% using specific drivers, and 6% related to the Nuclear Operations Support Charge.

Q. What is the amount of CSC forecasted for the 2022 Test Year and 2023 Subsequent Year?

A. FPL forecasts the CSC to affiliates to be approximately $114 million and $121 million in the 2022 Test Year and 2023 Subsequent Year, respectively. These amounts are reflected as a credit to administrative and general expenses 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 2022 Test Year, 56% of the CSC cost pool is expected to be allocated using specific drivers and 44% 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 has an understanding of the Affiliate Rule and properly charges or allocates costs as required.

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 processes document FPL's required affiliate transaction controls. 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 2020, 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 audit 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.

Q. Is FPL subject to reporting requirements by the FPSC 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 Reports for FPL and Gulf are provided in MFR C-31 in this filing.

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 and that FPL customers do not subsidize affiliates. Second, it will continue to lever the robust, highly specialized, commercial and technical talents of the broader business teams that it has amassed in performing these corporate and fleet services, which enable far greater benefits than it could ever deliver to customers as a standalone business.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of
Keith Ferguson was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KEITH FERGUSON

DOCKET NO. 20210015-EI

JULY 14, 2021

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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 ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit testimony in the proceeding?

A. Yes.

Q. Are you sponsoring or co-sponsoring any exhibits as part of your rebuttal testimony?

A. Yes. I am sponsoring the following exhibits:

- KF-9 – Comparison of Dismantlement Accruals at Different Discount Rates
- KF-10 – FPL's 2021 EEI Invoice

I am co-sponsoring the following exhibits:

- LF-10 – FPL's Notice of Identified Adjustments filed May 7, 2021 and Witness Sponsorship, filed with the rebuttal testimony of FPL witness Fuentes
- LF-11– FPL's Second Notice of Identified Adjustments filed May 21, 2021 and Witness Sponsorship, filed with the rebuttal testimony of FPL witness Fuentes

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address the following topics:

– Office of Public Counsel ("OPC") witness Dunkel's recommendation to use a higher annual discount rate in the calculation of dismantlement accruals; and,

– Florida Rising, Inc. ("FL Rising"), the League of United Latin American Citizens of Florida ("LULAC"), and the Environmental Confederation of Southwest Florida, Inc. ("ECOSWF") witness Rábago's proposal that FPL's request for capital recovery regulatory assets be denied and his proposal that the Florida Public Service Commission ("Commission") deny recovery of Edison Electric Institute ("EEI") dues.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony will demonstrate that the Company's request on the items identified above is reasonable and the intervenors' recommendations are flawed and should be rejected by the Commission. Specifically, I will demonstrate that:

- OPC witness Dunkel's recommendation to change the discount rate to calculate the dismantlement accrual is unsupported, unreasonable, out of line with accepted practice, and will result in higher accruals for future customers.
- FL Rising/ECOSWF/LULAC witness Rábago's suggestion that the Commission should deny FPL's request for regulatory assets for early retirements based on an alleged failure to demonstrate prudence ignores prior Commission orders and testimonies of current FPL witnesses

which do just that. In addition, his assertion that EEI dues should be denied recovery is based on unfounded speculation and ignores the way that FPL allocates and books these fees.

II. DISMANTLEMENT ACCRUALS

Q. What is the purpose of the dismantlement accrual?

A. The purpose of the dismantlement accrual is to collect the estimated cost of dismantling generation facilities at the time of retirement over the life of the facility. Per Rule 25-6.04364, Electric Utilities Dismantlement Studies, Florida Administrative Code ("F.A.C."), (the "Dismantlement Rule"), "[t]he dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement. The future costs less amounts recovered to date shall then be discounted in a manner that accrues the costs over the remaining life span of the unit." As required under the Dismantlement Rule, dismantlement studies are conducted typically every four years to reflect the latest cost estimates for dismantlement and life spans and revise annual dismantlement accruals accordingly.

Q. Please explain the Commission's policy regarding the discount rate to be utilized when calculating dismantlement accruals in a utility's dismantlement study.

A. Although the Dismantlement Rule does not explicitly state what discount rate should be applied, FPL has consistently utilized the compound inflation rate as the discount rate when calculating dismantlement accruals in its dismantlement studies for over 30 years. In addition, the same treatment has also been consistently utilized by other Florida investor-owned utilities ("IOUs"), most recently by Duke Energy Florida and Tampa Electric Company in their dismantlement studies filed in late 2020. To my knowledge, the Commission has consistently approved accrual calculations that utilize the compound inflation rate.

Q. Did FPL utilize a compound inflation rate as the discount rate to calculate dismantlement accruals in its 2021 Dismantlement Study?

A. Yes. FPL utilized a compound inflation rate for each component of dismantlement costs (labor, materials, etc.) at each unit, which results in an overall average of 2.82% discount rate in FPL's corrected 2021 Dismantlement Study filed on May 7, 2021. Please note OPC witness Dunkel's testimony referenced FPL's average inflation of 3.39%, which was derived from the original study rather than the corrected study. In addition, OPC witness Dunkel's recommendation to utilize an overall cost of capital of 6.40% is inappropriate and fails to recognize the Commission practice discussed above and the fact that the dismantlement reserve is an unfunded reserve. By nature, the amount of dismantlement costs FPL collects from its customers are not segregated and invested in a restricted account as a funded reserve would require. Instead, the amounts collected from customers are used to fund current operations, including any current dismantlement activities. The amounts collected help FPL avoid the need to raise incremental debt and equity in the period collected. In addition, the compound inflation rate is used to calculate the cost in future dollars needed at the time of dismantlement. Therefore, to appropriately allocate the dismantlement cost to customers over the life of the plant, it should also be used in the discount calculation.

Q. Has the Commission previously addressed the funding of a dismantlement reserve?

A. Yes. The Commission addressed whether a dismantlement reserve should be funded in Docket No. 890186-EI, which established the methodology for accruing dismantlement costs for fossil-fueled production plants and rejected the concept of a funded reserve for dismantlement costs. As stated in Order No. 24741 in the referenced Docket, "…it is in the best interest of the utility and its ratepayer to continue to provide for this dismantlement cost for the investor own[ed] utilities in this docket as an unfunded reserve."

Q. Can you please elaborate on why it is inappropriate to utilize an overall cost of capital to calculate dismantlement accruals?

A. Yes. As reflected on Exhibit KF-9, utilizing an overall cost of capital to calculate dismantlement accruals results in lower dismantlement accruals for current customers and much higher dismantlement accruals for future customers. In addition, it is unrealistic to assume that FPL's dismantlement reserve grows due to earnings on investments that do not actually exist. In contrast, customers are only funding the growth in dismantlement costs over time as a result of inflation, which is why it is appropriate to utilize a compound inflation rate to calculate dismantlement accruals as Florida IOUs have done for many years.

III. CAPITAL RECOVERY SCHEDULES

Q. Please explain the Commission's policy regarding the establishment of capital recovery schedules.

A. Per part (7)(a) of Rule 25-6.0436, Depreciation, F.A.C., (the "Depreciation Rule"), "[p]rior to the date of retirement of major installations, the Commission shall approve capital recovery schedules to correct associated calculated deficiencies where a utility demonstrates that (1) replacement of an installation or group of installations is prudent and (2) the associated investment will not be recovered by the time of retirement through the normal depreciation process." Although the Depreciation Rule does not address how a utility should petition for the establishment of capital recovery schedules, it has generally been FPL's practice to present them for Commission approval in either a base rate proceeding or separate docket.

Q. Does the Depreciation Rule address how a utility should demonstrate whether early retired generating plant is reasonable and in the best interest of customers?

A. No, it does not. However, it has been FPL's practice to provide evidence either through economic analyses and/or reliability considerations on the prudency of early retired generating plant to the Commission for their review when establishing capital recovery schedules.

Q. Has FPL demonstrated that the early retired plants included in the proposed capital recovery schedules reflected in Exhibit KF-4 are reasonable and in the best interest of customers?

A. Yes. Contrary to FL Rising/LULAC/ECOSWF witness Rábago's assertion that FPL has not presented evidence related to each early asset retirement and its benefits to customers, please see below as to where FPL has in fact provided such evidence in this proceeding similar to the information provided in a prior docket involving the early retirement of the Martin and Lauderdale units, where the Commission found those retirements to be prudent:

- Martin Units 1 and 2 – Docket No. 20180155; Order No. PSC-2019-0045-PAA-EI
- Lauderdale Units 4 and 5 – Docket No. 20180155; Order No. PSC-2019-0045-PAA-EI
- Gulf Clean Energy Center Coal-to-Gas Conversion – FPL witness Sim (Exhibit SRS-7)
- Manatee Units 1 and 2 – FPL witness Sim (Exhibit SRS-3)
- Scherer Unit 4 – FPL witness Bores (Exhibit SRB-11)
- 500 kV Transmission – FPL witness Spoor (pages 21 and 22 of direct testimony)

In addition, because each of the retirements listed above is being replaced by assets that provide significant benefits both to current and future customers, it is appropriate for the Commission to conceptually consider the recovery of the remaining book value of the early retired assets as part of the investment in the replacement assets even though they are accounted for separately. Therefore, FPL's proposed ten-year recovery period balances cost recovery and bill impacts between current and future customers.

IV. EEI MEMBERSHIP DUES

Q. Please explain how the EEI membership benefits customers.

A. EEI is a time-honored and recognized industry association that, among other things, helps electric utilities keep in contact, learn best practices from each other, stay current in training, and it provides research and information for its members. EEI also offers a variety of industry related conferences where electric utilities exchange ideas, discuss, and develop best practices.

Q. How are EEI membership fees billed?

A. The Company receives an annual bill for its membership with EEI. This bill is outlined in detail and it segregates the portion of dues related to policy making, which FPL records below-the-line to FERC Account 426.4, (Expenditures for Certain Civic, Political and Related Activities), and charitable contributions, which FPL records below-the-line to FERC Account 426.1, (Donations). Since these FERC accounts are below-the-line, they are not included in the

Company's cost of service or costs recovered from customers. I have included a copy of FPL's most recent EEI membership invoice as Exhibit KF-10 to my testimony which reflects the percentages of each amount on the bill that are considered policy making or charitable contributions that the Company booked to FERC Account 426.4 or 426.1, respectively. The remaining amount of the billwas recorded above-the-line and the net amount after allocations to affiliates as discussed below is included in FPL's cost of service.

Q. Has the Commission allowed recovery of EEI membership dues in the past?

A. Yes. The Company has historically included in its cost of service the recoverable amount related to its membership with EEI. To my knowledge, the Commission has never disallowed the costs of this membership.

Q. Do you agree that FPL customers pay for EEI Political Speech?

A. No. On pages 27 through 28 of FL Rising/LULAC/ECOSWF witness Rábago's testimony, he incorrectly claims that customers are forced to pay for the portion related to political and policy advocacy work that EEI conducts. As explained above, the Company removes the component of the bill related to policy and political activities as well as charitable contributions and charges them to shareholders instead of including them in the cost of service paid by customers. In addition, approximately 30% of the membership fees are allocated out of FPL to its affiliates via the Corporate Service Charge, which further ensures that FPL customers only pay for the portion of the membership that benefits FPL activities.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Sam Forrest was inserted.)

ERRATA SHEET

WITNESS: **SAM FORREST – DIRECT TESTIMONY**

PAGE #	**LINE #**	**CHANGE**
25	2	Remove "January" and insert "October 5,"
25	6	Remove "January" and insert "October 5,"
25	8	Remove "2040" and insert "2050"
25	9	After "The PIRA Energy Group", insert "for natural gas, and both the annual projections from The PIRA Energy Group (2025-2040) and the real rate of escalation from the Energy Information Administration ("EIA") (2041-2050) for fuel oil"
25	10	Remove "2040" and insert "2050"

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF SAM FORREST

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Sam Forrest. My business address is 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 of the Energy Marketing and Trading ("EMT") Business Unit.

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

A. I am responsible for the overall direction and management of the EMT Business Unit, which handles FPL's short-term and long-term fuel management and operations. These fuels include natural gas, residual and distillate fuel oils, and coal. Additionally, EMT is responsible for FPL's long-term fuel transportation and storage contracts, power origination activities and short-term power trading, and operations. EMT is an active participant in the short-term and long-term natural gas markets throughout the Southeastern United States.

Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science in Electrical Engineering from Texas A&M University and a Master of Business Administration from the University of Houston. Prior to being named Vice President of EMT for FPL in 2007, I was employed by Constellation Energy Commodities Group as Vice President, Origination. In this capacity, I was responsible for managing a team of power originators marketing structured electric power products in Texas, the Western

United States, and Canada. Prior to my responsibilities in the West, I was responsible for Constellation's business development activities in the Southeast U.S.

Before joining Constellation, from 2001 to 2004, I held a variety of energy marketing and trading management positions at Duke Energy North America ("DENA"). Prior to DENA, I was employed by Entergy Power Marketing Corp. ("EPMC") in several positions of increasing responsibility, including Vice President, Power Marketing following EPMC's entry into a joint venture with Koch Energy Trading.

Prior to my entry into the energy sector, I was involved with a successful start-up organization in the automotive industry from 1996 to 1998. From 1987 to 1996, I worked for AlliedSignal Aerospace at the Johnson Space Center in Houston, Texas, in increasing roles of responsibility.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- SAF-1 Incentive Mechanism Comparison for Period 2013-2020
- SAF-2 Proposed New Total Gains Schedule

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. No.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain and support FPL's request to extend the current incentive mechanism that was originally approved by Order No. PSC-13-0023-S-EI, dated January 14, 2013, in Docket No. 120015-EI (the "Incentive Mechanism") and approved for continuation, with certain modifications, by Order No. PSC-16-0560-AS-EI, dated December 15, 2016, in Docket No. 160021-EI. I will provide: (i) a description of the Incentive Mechanism under which FPL operates, including a review of the results since its inception; (ii) specifics of FPL's request to update the variable power plant Operation and Maintenance ("O&M") rate; (iii) details of FPL's request to continue the Incentive Mechanism as currently structured; and, (iv) an overview of ongoing optimization costs. In addition, I will explain the rationale behind FPL's decision to retire its ownership share in Scherer Unit 4 and provide support for the overall value of the transaction for FPL's customers. Lastly, my testimony will describe the benefits that all customers will derive from the joint dispatch of the consolidated FPL and former Gulf Power Company ("Gulf") systems.

Q. Please summarize your testimony.

A. The Incentive Mechanism that was approved as part of FPL's 2012 Rate Settlement and subsequently extended through the end of 2021 as part of FPL's 2016 Rate Settlement, was designed to expand opportunities for FPL to create gains on short-term wholesale power transactions (economy sales and economy purchases) and optimize the availability and utilization of other assets. The purpose of the Incentive Mechanism was to provide increased value for FPL's customers while also providing an incentive to FPL if certain customer-value thresholds were achieved. It absolutely has worked as intended and designed. Customers have benefitted from the expanded focus on asset optimization and the incentives have proven appropriate to FPL.

FPL proposes that the Commission approve the Incentive Mechanism as an ongoing program independent of future base rate proceedings and, following the four-year term of FPL's base rate request, to move review of the mechanism to the annual Fuel and Purchased Power Cost Recovery Clause ("Fuel Clause") proceeding. This will allow the establishment of an appropriate set of incentives for a four-year period commencing 2022 and an opportunity to review and adjust the mechanism in the subsequent Fuel Clause proceeding without regard to the timing of the next base rate proceeding. FPL's proposal, including adjustments to the current incentive levels requested in this proceeding, will help ensure that the Incentive Mechanism remains a successful program going forward as FPL continues identifying and acting upon opportunities for gains that create substantial value for customers.

FPL is always looking for ways to bring value to its customers and its partners. As FPL has continued to modernize its fleet with efficient natural gas plants and an increased focus on solar, the legacy coal plants on its system have become increasingly more expensive by comparison. Both the short-term economic dispatch costs, as well as the ongoing capital projects and O&M obligations, have made coal plants one of FPL's key areas of focus from a cost reduction perspective. FPL approached JEA regarding a potential shutdown of Scherer Unit 4. Through negotiations, FPL and JEA reached an agreement to retire their respective shares of Scherer Unit 4. This agreement will result in significant value for FPL's customers. The details and other components of the Scherer retirement request are provided in the testimonies of FPL witnesses Bores and Fuentes.

Numerous FPL witnesses detail the significant economic benefits that come from the consolidation of the FPL and Gulf systems into one system. Many of these benefits are made possible through the economic dispatch of the consolidated generation system such that the most efficient (or least cost) generating facilities are run to serve the combined load, taking into consideration any limitations or constraints that may exist. By utilizing more efficient units to serve customers, wherever located, there are significant savings to be achieved.

Finally, the fuel forecasts used for the long-term analyses in this case are appropriate. Utilizing third party sources, FPL has provided a forecast for natural gas, coal, and oil that is consistent with the approach it has taken for more than a decade.

II. BACKGROUND ON THE INCENTIVE MECHANISM

Q. What were the circumstances that led FPL to propose the Incentive Mechanism?

A. Prior to the 2012 Rate Settlement, FPL operated under the Commission's standard sharing mechanism for gains on economy sales ("Prior Mechanism"). The designed sharing by FPL occurred if gains on economy power sales exceeded the three prior year average of gains on sales. While the Prior Mechanism provided an incentive for creating gains for customers, for FPL's circumstances it proved overly narrow and restrictive in two important respects. First, it only applied to economy *sales.* There are market conditions that provide substantial opportunities to create customer gains from economy *purchases* as well. Second, the Prior Mechanism did not address the opportunities to create gains from optimizing the use of other utility assets, such as natural gas transportation and gas storage rights. Accordingly, as part of the

2012 Rate Settlement, FPL proposed to substitute the more broadly-based Incentive Mechanism in place of the Prior Mechanism. The Commission approved the Incentive Mechanism as "a four-year pilot program" as a part of the 2012 Rate Settlement. The initial pilot was extremely successful, providing substantial customer value. The Commission then authorized FPL to continue the Incentive Mechanism for the term of the 2016 Rate Settlement, subject to certain modifications to maintain the program's success. The Incentive Mechanism is currently set to expire at the end of 2021 with the adoption of new base rates in 2022.

Q. Please describe the modifications that were made to the Incentive Mechanism in FPL's 2016 rate case and approved by Order No. PSC-16-0560-AS-EI.

A. There were two specific modifications made to the Incentive Mechanism in FPL's 2016 Rate Settlement. First, the sharing threshold was reduced from $46 million to $40 million. The sharing intervals and percentages remained unchanged from the original Incentive Mechanism.

The second modification made to the Incentive Mechanism involved variable power plant O&M costs. Under the original Incentive Mechanism, FPL was allowed to recover variable power plant O&M costs incurred to make wholesale sales above 514,000 MWh (the level of wholesale sales that were assumed in forecasting FPL's 2013 Test Year power plant O&M costs reflected in the MFRs filed in FPL's 2012 rate case). Under the modified Incentive Mechanism, FPL nets economy sales and purchases to determine the overall impact of variable power plant O&M. If FPL executes more economy sales than economy purchases, FPL recovers the net amount of variable power plant O&M incurred in that year. Conversely, if economy purchases exceed economy sales, FPL's customers receive a credit for the net variable power plant O&M that has been saved in that year. The per-MWh variable power plant O&M rate that FPL uses to calculate these costs, as identified in FPL's 2017 Test Year MFRs filed with the 2016 Rate Petition, is $0.65/MWh.

Q. Please describe the current Incentive Mechanism.

A. The Incentive Mechanism is designed to create additional value for FPL's customers while also providing an incentive to FPL to achieve certain customer-value thresholds. The Incentive Mechanism is very straightforward in that it simply adds incentives for FPL to create additional value for customers above the levels that were projected at the time the mechanism was approved. As I previously stated, FPL was authorized under the FPSC-approved 2016 Rate Settlement to continue the Incentive Mechanism. Under the current Incentive Mechanism, customers receive 100% of the gains up to the sharing threshold of $40 million. Incremental gains above $40 million are shared between FPL and customers as follows: customers receive 40% and FPL receives 60% of the incremental gains between $40 million and $100 million; and, customers receive 50% and FPL receives 50% of all incremental gains above $100 million.

FPL has created additional value by expanding economy sales into other regions beyond the Southeast, as well as adding new activities such as natural gas storage optimization, natural gas sales, capacity releases of natural gas transportation and selling rights on third-party electric transmission when they are not needed by FPL. Additionally, FPL has, on occasion, outsourced a portion of the optimization function of assets such as natural gas transportation to a third party in the form of an asset management agreement ("AMA") in exchange for being paid a premium. The revenues from such AMAs also are included under the Incentive Mechanism.

As part of the program, FPL is entitled to recover through the Fuel Clause the reasonable and prudent incremental O&M costs incurred in implementing its expanded asset optimization measures. These include the incremental personnel, software and associated hardware costs incurred by FPL (which are not included in FPL's current base rate request), as well as variable power plant O&M costs as previously described in my testimony. The symmetrical approach to recovery of or providing a credit for variable power plant O&M is a fair and straightforward approach both for customers and for FPL, as only the O&M costs actually incurred (or saved) are passed through (or credited) to customers.

III. PEFORMANCE OF THE INCENTIVE MECHANISM

Q. Overall, how has the Incentive Mechanism performed?

A. As can be seen in Exhibit SAF-1, the Incentive Mechanism has clearly worked as intended for both FPL's customers and FPL. Using the actual results of the years 2013 through 2020, after incremental O&M expenses are netted, there was a total benefit of $406.7 million from all Incentive Mechanism activities. Of this total, customers received $354.5 million and FPL received $52.2 million.

Q. Has the Incentive Mechanism yielded greater value for FPL customers?

A. Yes. FPL has been able to deliver an additional $122.6 million in benefits over the last eight years through its natural gas optimization activities that were authorized under the Incentive Mechanism as shown in Exhibit SAF-1. FPL's expanded approach under the Incentive Mechanism better facilitates our ability to capture transactions that deliver value to our customers.

IV. EXTENDING THE INCENTIVE MECHANISM

Q. Should the Incentive Mechanism be extended past the expiration of the 2016 Rate Settlement at the end of December 2021?

A. Yes. The Incentive Mechanism has worked well, and it is in the mutual best interests of FPL's customers and FPL for it to remain in effect. Accordingly, FPL proposes that the Commission approve the Incentive Mechanism as an ongoing program independent of future base rate proceedings and, following the four-year term of FPL's base rate request, to move review of the mechanism to the annual Fuel Clause proceeding. FPL's proposal, including adjustments to the current incentive levels requested in this proceeding, will help ensure that the Incentive Mechanism remains a successful program as FPL continues identifying and acting upon opportunities for gains that create substantial value for customers.

Q. If the Commission were to approve the Incentive Mechanism as requested by FPL, would the parameters remain in place on a permanent basis?

A. No. While FPL believes that the concept and structure of the Incentive Mechanism should be approved as an ongoing program, there are certain parameters included in the Incentive Mechanism that warrant review and possible adjustments on a periodic basis. These parameters include optimization activities, variable power plant O&M rates, and savings thresholds. Approval of the Incentive Mechanism would include the parameters as proposed in my testimony for a four-year period, thereafter with an opportunity to review and adjust the mechanism in the subsequent Fuel Clause proceeding without regard to the precise timing of the next base rate proceeding.

Q. After the four-year period, what forum does FPL believe is appropriate to facilitate the review and potential adjustments to these parameters?

A. FPL believes that the annual Fuel Clause proceedings are the appropriate forum to handle a review of these parameters and address whether any adjustments are warranted. All activities and results of the Incentive Mechanism reside in the Fuel Clause today. Each year, FPL files the results of its optimization activities for the prior year as part its Final True-Up Filing in the Fuel Clause. Therefore, it makes sense for all aspects of the Incentive Mechanism to fully reside in the annual Fuel Clause proceedings.

Q. How does FPL propose that the review and potential adjustment process be conducted in the Fuel Clause?

A. FPL proposes that every four years, as part of its annual Projection Filing in the Fuel Clause, FPL would include in its testimony support for whether changes to the "adjustable" parameters were warranted or not. The Incentive Mechanism "adjustable" parameters would be an issue in the docket every four years. This methodology would allow the Commission Staff and intervenors the opportunity, through the normal discovery, testimony and hearing process to fully review and weigh in on any proposed changes prior to a decision by the Commission. Ultimately, the Commission would decide at hearing every four years on approval of the "adjustable" parameters.

V. EXPANDING THE INCENTIVE MECHANISM

Q. With the consolidation of the FPL and Gulf systems, please describe the impact to the Incentive Mechanism program.

A. There will be one set of commonly owned and operated assets with the consolidation of the FPL and Gulf systems. If the Commission approves the continuation of the Incentive Mechanism, it would be applied to the consolidated FPL assets. Optimizing the consolidated assets as a single portfolio should help create more opportunities to increase value for customers.

Q. Does FPL propose to add any other forms of asset optimization beyond what is currently approved in the Incentive Mechanism program?

A. Yes. Under the current Incentive Mechanism program, FPL is authorized to optimize natural gas supply and capacity. As I explained previously, the optimization of these assets has provided and will continue to provide significant benefits to FPL's customers. However, since the Incentive Mechanism was originally implemented, FPL has and will continue to modernize its generation fleet as explained by FPL witness Broad, including the addition of cleaner, more cost-effective, and fuel-efficient generation and renewable energy sources. Further, as explained by FPL witness Valle, FPL continues to look for opportunities to reduce the Company's carbon footprint and provide reliable, cost-effective, and emission-free energy.

Therefore, FPL seeks to update the assets that may be optimized under the Incentive Mechanism program to properly reflect the modernization and transformation of FPL's generation fleet. Specifically, FPL seeks to expand the benefits of the Incentive Mechanism program by optimizing all fuel sources when it is reasonable and in the best interests of customers to do so based on the system requirements, market demand, and market price of the fuel or capacity at the time. This would allow FPL to expand optimization to include all fuel sources, including natural gas, capacity, manufactured gas, mixed gas, renewable natural gas, hydrogen gas, and other fuel sources. In addition, this will ensure that FPL can continue to optimize the availability and utilization of FPL's modern assets to provide increased value for FPL's customers. For example, as discussed in more detail by FPL witness Valle, FPL is introducing hydrogen through the "green hydrogen" fuel generation pilot at the Okeechobee Clean Energy Center ("OCEC"). This pilot will produce a supplemental, carbon-free fuel source to be used at OCEC. If FPL's proposal to expand optimization to include all fuels is approved, hydrogen produced at the facility (or future facilities) may be made available to the market and be sold at prices above the cost of production. Any value created through this process would be included in the Incentive Mechanism.

Additionally, given the significant investment in solar over the last several years, FPL has banked the Renewable Energy Credits ("REC" or "RECs") on behalf of customers. Albeit somewhat limited, RECs have value in the market, and FPL proposes to monetize the RECs as part of the Incentive Mechanism program.

VI. UPDATING THE INCENTIVE MECHANISM

Q. Is FPL proposing any changes to the savings thresholds that are defined in the current Incentive Mechanism?

A. Yes. FPL is proposing to reduce the number of savings thresholds from four to three. This proposed reduction in the savings thresholds will have no impact on how benefits are calculated and shared, but instead will help simplify the Total Gains Schedule that FPL files annually as part of its Final True-Up in the Fuel Clause. Under the current Incentive Mechanism structure, there are four thresholds defined: Threshold 1 (less than or equal to $30 million), Threshold 2 (less than or equal to $40 million), Threshold 3 (greater than $40 million and less than or equal to $100 million), and Threshold 4 (greater than $100 million). The $30 million threshold represented a baseline value of benefits that FPL believed it could achieve from short-term power sales gains and purchased power savings. Sharing only occurs if FPL is successful in delivering an additional $10 million in value through its expanded optimization activities. Therefore, customers receive 100% of the benefits up to $40 million and the $30 million threshold serves no purpose for any sharing calculations under the Incentive Mechanism.

FPL is proposing to simplify the structure by reducing the number of thresholds. FPL's proposal is to set Threshold 1 at less than or equal to $40 million as this represents the level up to which customers receive all of the benefits. Threshold

2, the level at which sharing begins, will be greater than $40 million and less than or equal to $100 million. Threshold 3, the level at which the sharing percentages change, will be greater than $100 million. An example of the proposed new Total Gains Schedule is included as Exhibit SAF-2.

Q. Does FPL believe it is appropriate to maintain the sharing threshold at $40 million?

A. Yes. FPL believes that the current sharing threshold of $40 million approved in Order No. PSC-16-0560-AS-EI is still appropriate. As discussed later in my testimony, with the consolidation of the two FPL and Gulf utility systems into one, FPL proposes to optimize the assets as one system. This will create incremental opportunities, albeit somewhat limited given the relative size of Gulf compared to FPL. At the same time, however, there are diminished opportunities on FPL's system given the proposed retirements of Manatee 1 and 2 and Scherer 4. These units have created opportunities to purchase lower cost power in the past that will no longer be available. Given the offsetting impacts of the addition of the Gulf asset and the retirements mentioned, FPL believes it is appropriate to leave the sharing threshold unchanged.

Q. Is FPL proposing a change to any other aspects of the Incentive Mechanism?

A. Yes. FPL proposes to change the per-MWh rate for variable power plant O&M based on the 2022 Test Year MFRs utilizing the same methodology that was applied to the 2017 Test Year MFRs. The updated calculation results in a decrease in the per-MWh rate, from $0.65/MWh to $0.48/MWh. This decrease is a result of FPL's success in reducing fossil fleet O&M and capital expenditures associated with operating and maintaining its fleet, as described in the testimony of FPL witness Broad.

VII. RETIREMENT OF SCHERER UNIT 4

Q. Please provide background information on FPL's ownership interest in Scherer Unit 4.

A. More than thirty years ago, in December 1990, FPL and JEA entered into an agreement ("Scherer Agreement") with Georgia Power to jointly own Plant Robert W. Scherer ("Scherer") Unit No. 4 ("Unit 4"), an 850 MW coal fired generating unit located in Macon, GA. Under the agreement, FPL agreed to own a 76.36% undivided interest in Scherer Unit 4, and JEA agreed to own a 23.64% undivided interest of that same unit. In addition to their joint ownership in Unit 4, JEA and FPL also own undivided interests in the common facilities of Units 3 and 4, as well as undivided interests in the Scherer common facilities. FPL owns 38.18% of the common facilities related to Units 3 and 4 and 19.09% of the common facilities related to Units 1-4. Additionally, both FPL and JEA maintain coal stockpiles for their own account, and each company owns a portion of the Scherer materials and spares inventory.

Q. Why has FPL decided to retire its ownership interest in Scherer 4?

A. FPL continually looks for opportunities to bring value to its customers. The modernization of FPL's fleet over the last decade, as well as the addition of solar to the FPL system, has increasingly pushed coal generation to the bottom of the dispatch stack. Ongoing capital costs and O&M obligations have rendered FPL's legacy coal plants as prime candidates for overall cost reduction efforts. In addition, because of its interest in Scherer Unit 4, FPL is obligated to make an annual transmission service payment which allows for the transmission of electricity from the unit in Georgia to the FPL balancing authority. FPL makes this payment regardless of the amount of energy FPL receives from Scherer Unit 4.

Q. Does FPL have the ability to retire its percentage ownership of Scherer Unit 4 if JEA does not also retire its share?

A. No. Without JEA's agreement to retire its share, FPL would not be relieved of its obligations under the Scherer Agreement as it relates to the operation of Unit 4. The dispatch of Unit 4 requires each owner receive its commensurate share of the output of the unit and to fulfill other obligations under the agreement. For example, when JEA exercises its option to dispatch 200 MW, FPL must also dispatch at least 200 MW in order to meet the minimum operating limit of the unit. FPL cannot eliminate this obligation without JEA agreeing to retire its share.

Q. Please summarize the discussions that led to the agreement to retire Scherer Unit 4.

A. In the early part of 2020, JEA and FPL began discussing the potential retirement. One of the concerns expressed by JEA was the ongoing bond obligations related to its Scherer ownership and JEA's need to pay off the bonds in the event of a retirement. In order to finance its ownership of Scherer Unit 4, JEA had issued and sold bulk power supply system revenue bonds pursuant to a series of amended resolutions. At the time negotiations began, there were approximately $100 million in remaining payments due on those bonds. FPL ultimately agreed to make a Consummation Payment to satisfy those obligations. Without this payment to JEA, there would be no opportunity to retire this unit and unlock the significant value of the overall transaction for FPL's customers. That value is addressed in the testimony of FPL witness Bores. The recovery of this Consummation Payment is covered in the testimony of FPL witness Fuentes.

Q. What are the projected overall benefits that FPL's customers will receive through the retirement of Scherer 4?

A. As further described in the testimony of FPL witness Bores, FPL's customers will see a thirty-year cumulative present value revenue requirement ("CPVRR") benefit of nearly $583 million as a result of this retirement.

Q. What are the next steps in the retirement process?

A. As noted in the testimony of FPL witness Bores, FPL and JEA intend to retire Scherer Unit 4 effective January 1, 2022. On September 11, 2020, both FPL and JEA provided notice to Georgia Power and the other co-owners of Scherer Units 1-3 of the plans for retirement.

Q. Will FPL have any ongoing obligations at the Scherer facility once Unit 4 is retired?

A. Yes. As mentioned earlier in my testimony, FPL owns undivided interests in the Scherer common facilities related to the operation of the plant. These facilities include such things as the rail delivery system, coal operations infrastructure, water treatment systems, site administrative buildings, and the electric distribution system of the plant. There will be ongoing costs for these common facilities. While the retirement of Unit 4 will reduce certain common facilities costs going-forward, FPL's and JEA's obligations for these common facilities are not eliminated as part of the retirement. These costs are reflected in the economic analysis and customer savings presented by FPL witness Bores.

Q. Do you have any concerns regarding the reduction in fuel diversity as a result of the retirement of Scherer 4?

A. No. Over the past two decades, FPL has taken significant strides to increase the efficiency of its system, along with reducing the emissions profile of its generating fleet. In order to achieve these benefits for customers, FPL has increased its reliance on natural gas and on solar. This increased reliance on natural gas has been met with a focus on improving the robustness of the gas delivery system. The addition of Sabal Trail Transmission, LLC and Florida Southeast Connection, LLC increased the deliverability of natural gas into and within Florida. In addition, FPL added a second natural gas storage facility to its portfolio when it signed a contract with Southern Pines Energy Center. Several upstream gas positions on the Southeast Supply Header, Gulf South Pipeline Company, LP, and Transcontinental Gas Pipe Line Company, LLC also give FPL tremendous flexibility in terms of where gas needs to be purchased and has reduced the reliance on more traditional sources of supply. Finally, FPL has installed distillate storage at the majority of its natural gas combined cycle facilities and can switch to this backup fuel when loads dictate or when there are fuel emergencies, such as in February 2021. During the third week of February, Texas and surrounding states experienced a cold weather event so significant Florida had to deal with reduced gas deliveries as producers and pipelines dealt with freezing conditions on their facilities. Due to the flexibility offered by the supply portfolio, FPL was able to continue to deliver gas to its facilities without issue and as loads increased on FPL's system, we were able to switch combustion turbines at a few of our combined cycle sites over to distillate fuel oil to work through the gas limitations. FPL was able to meet load thanks to the flexibility in the system and the robustness of the infrastructure this Commission has found prudently installed over the years.

VIII. CONSOLIDATED SYSTEM DISPATCH

Q. Please describe the dispatch opportunities for the combined fleet of generating resources.

A. There are significant economic benefits that come from being able to dispatch the consolidated FPL and Gulf systems as one system. As discussed at length in FPL witness Sim's testimony, the total value created by interconnecting the two sets of generating resources via the North Florida Resiliency Connection transmission line ("NFRC") is projected to be $677 million in CPVRR savings. This value comes from being able to dispatch generation from any part of the consolidated system such that the most efficient (or least cost) generating facilities are run to serve the combined load, taking into consideration any limitations or constraints that may exist. As mentioned in FPL witness Sim's testimony, during 2019, Gulf's fossil-fueled generating units had a system average heat rate of approximately 9,000 Btu/kWh. FPL's system average heat rate in 2019 was remarkably better at approximately 7,000 Btu/kWh.

By utilizing more efficient units to serve customers, wherever located, there are significant savings to be achieved. As an example, if you assume $3.00/MMBtu gas delivered to one part of the combined system, enabling those units to utilize 100 MW of system average energy to displace system average energy on another part of the system for one week, that is a total savings of approximately $100,000. As FPL witnesses Sim and Spoor explain in more detail, there is as much as 850 MW of transfer capability on the NFRC, providing the potential for savings for customers. The value of this potential is covered by FPL witness Sim.

IX. FUEL FORECASTING

Q. FPL witness Sim referred to long-term fuel cost forecasts that were used to support his testimony. Can you explain how those forecasts are developed?

A. Yes. FPL's fuel price forecast methodology is consistent for oil and natural gas. For oil and natural gas commodity prices, FPL's price forecast applies the following methodology:

a. For the current + 2 years (2020-2022), the methodology used the January 2020 forward curve for New York Harbor 0.7% sulfur heavy oil, WTI Crude Oil, Ultra-Low Sulfur Diesel ("ULSD") fuel oil, and Henry Hub natural gas commodity prices;

b. For the next two years (2023 and 2024), FPL used a 50/50 blend of the January 2020 forward curve and the most current projections at the time from The PIRA Energy Group;

c. For the 2025 through 2040 period, FPL used the annual projections from The PIRA Energy Group; and,

d. For the period beyond 2040, FPL used the real rate of escalation from the Energy Information Administration ("EIA"). In addition to the development of oil and natural gas commodity prices, nominal price forecasts also were prepared for oil and natural gas transportation costs. The addition of commodity and transportation forecasts resulted in delivered price forecasts.

FPL's price forecast methodology is also consistent for coal prices. Forecasted coal prices were based upon the following approach:

a. JD Energy provides regular (once every 1-2 months) short-term price forecasts (currently through 2021 issued in December 2019) for Powder River Basin ("PRB") minemouth/FOB coal;

b. JD Energy also provides a long-term price forecast through 2065 of the delivered prices of coal to Scherer. The most recent forecast was issued in September 2019;

c. The short-term delivered coal price forecast for Plant Scherer is updated with PRB minemouth/FOB coal price updates from JD Energy while keeping the long-term prices the same as the September 2019 long-term forecast; and,

d. Beyond 2065, prices are escalated at JD Energy's annual price escalation from 2064 to 2065.

The long-term fuel forecasts resulting from the application of this methodology for oil, natural gas, and coal are presented in FPL witness Sim's Exhibit SRS-5. This methodology provides a reasonable fuel price forecast for planning purposes, given the information available at the time the fuel forecast is developed.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Sam Forrest was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF SAM FORREST

DOCKET NO. 20210015-EI

JULY 14, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sam Forrest and my business address is Florida Power & Light Company ("FPL"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibit:

- SAF-3 2013-2020 Aggregate Incentive Mechanism Comparison

Q. Please summarize your rebuttal testimony.

A. The proposed Incentive Mechanism has worked well for customers since its inception, with nearly $65 million in incremental benefits delivered to customers since the program started in 2013. However, FPL is proposing to update the program to reflect changes in FPL's system and the markets in which we participate. We believe these updates are in the best interests of customers and continue the incentives that have been put in place to bring benefits to our customers.

The retirement of FPL's share of Scherer Unit 4 is expected to produce significant savings for customers. FPL witness Bores addressed the value in his direct testimony, showing $583 million in direct customer savings from the retirement. It is important to understand there would be no retirement, and thus no $583 million in savings, without the $100 million Consummation Payment being made to JEA. It is also important to understand there was no link between the retirement decision and the Power Purchase Agreement ("PPA") negotiated between FPL and JEA. JEA was free to make any decision they wanted with respect to replacement power. JEA selected the FPL PPA from other alternatives received by JEA. And while the retirement of Scherer 4 reduces FPL's reliance on coal as a fuel source, there are several actions that have been taken by FPL to address the issue of fuel diversity. In fact, FPL's energy contribution from natural gas decreases in 2022, the year of the proposed retirement, and every year thereafter, in large part due to the amount of solar generation being added to the system. Further, FPL has made significant efforts over the years to improve the robustness of the natural gas delivery system and the backup fuel capability at its combined cycle sites.

II. INCENTIVE MECHANISM

Q. Do you agree with OPC witness O'Donnell's contention there is not enough information to understand how the requested expansions of the incentive mechanism will work and therefore should not be approved?

A. No. There is substantial evidence in the record regarding the success of the Incentive Mechanism to date. In fact, as shown on Exhibit SAF-3, FPL has added nearly $65 million in incremental value since the program's inception. Because the Incentive Mechanism is an opportunity-based program, all facts related to expected results cannot be known prior to implementation. Following the original approval in 2012, modifications were made to the program in 2016 to maintain the program's success. These changes benefitted customers, as well as maintained the proper incentives for FPL. FPL is now proposing to expand the mechanism to include all fuel products, as well as Renewable Energy Credits ("RECs"). These incremental products will be entirely additive to what is already a very successful program and will not detract in any way from the optimization activities that already take place, ultimately creating additional economic benefits for customers.

III. RETIREMENT OF SCHERER UNIT 4

Q. Do you agree with FIPUG witness LaConte that the Commission should reject[1] the $100 million Consummation Payment being made to JEA in consideration of the retirement of Scherer Unit 4?

A. No. To be clear, there are no savings associated with the retirement of Scherer Unit 4 without JEA's participation. Through numerous discussions with JEA, there was little progress made on retirement due to a number of factors, most notably the outstanding debt JEA held on their portion of Scherer Unit 4. FPL recognized the value to its customers from the retirement of the unit and was able to negotiate the Consummation Payment in order to incent JEA to agree to

[1] Witness LaConte's Direct Testimony, page 32: lines 15-18.

the retirement. The $583 million in CPVRR unlocked to FPL's customers from this retirement does not happen without the payment.

Q. Do you agree with FEA witness Gorman's contention[2] that FPL should recover the $100 million Consummation Payment through its PPA with JEA?

A. No. Mr. Gorman is directly linking the decision to retire Scherer Unit 4 and the JEA PPA as one transaction. FPL's decision to retire Scherer was made independent from agreeing to the PPA with JEA. With respect to the decision to retire Scherer, there were discussions between the parties over the span of a few years, with JEA expressing hesitation to start negotiating, having just announced the retirement of the St. Johns River Power Park, as approved by the Commission in Order No. PSC-2017-0145-AS-EI in Docket No. 20170123-EI. As the discussions around Scherer began to take hold, there were a number of issues that needed to be addressed, two of which were the outstanding debt that JEA held on their portion of Scherer, as well as the replacement of the roughly 200 MW JEA would be losing as a result of the retirement. It is my understanding that JEA went to the market to pursue a PPA for replacement power. As part of that process, FPL offered to supply the 200 MW and JEA selected our offer. There was no link between the Consummation Payment and the decision to select FPL's PPA offer. The fact both are addressed in the Cooperation Agreement between the parties only goes to document the decisions made during the process but does not link the two.

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[2] Witness Gorman's Direct Testimony, page 14: lines 15-17.

Q. OPC witness Smith discussed a number of issues related to the decision to retire Scherer, including fuel diversity, Georgia Power, and a potential sale of FPL's ownership share of Scherer Unit 4[3]. How do you respond?

A. In my direct testimony, I discuss the steps that have been taken to address the robustness of the natural gas delivery system that FPL relies on, as well as the backup fuel that is available across much of FPL's combined cycle fleet. Additionally, with the addition of Gulf Power Company ("Gulf"), FPL's reliance on natural gas is projected to drop in 2022 and every year thereafter. As shown in Schedule 6.1 of FPL and Gulf's 2021 Ten Year Site Plan[4], every megawatt-hour that is lost from the retirement of Scherer Unit 4 is more than offset by a megawatt-hour of new solar generation. This creates a measure of fuel diversity that isn't addressed by Mr. Smith.

With respect to Mr. Smith's mention of Georgia Power and Scherer, FPL's system is different than Georgia Power's and FPL's approach to resource planning is not the same as Georgia Power's approach. In fact, while Georgia Power may hold Scherer in "higher regard" than FPL and continues to invest in its coal fleet, FPL has sought and received approval from this Commission to retire Cedar Bay (Order No. PSC-15-0401-AS-El, Docket No. 150075-EI), Indiantown Cogeneration LP (Order No. PSC-16-0506-FOF-EI, Docket No. 160154-EI), and St. Johns River Power Park (Order No. PSC-2017-0145-AS-

[3] Witness Smith's Direct Testimony, page 45: line 20 through page 47: line 11

[4] Docket No. 20210000-OT Florida Power & Light Company and Gulf Power Company's 2021-2030 Ten Year Power Plant Site Plan

EI, Docket No. 20170123-EI). FPL has been clear regarding its intent to reduce its reliance on coal, improve operational efficiencies, and reduce its environmental footprint.

Additionally, Mr. Smith suggests the retirement of Scherer Unit 4 will expose FPL's customers to higher costs from natural gas price increases. As I noted earlier in this discussion, FPL's reliance on natural gas is actually projected to decrease from 2021 to 2022, and every year thereafter, as a result of the additional solar being added to its system. From a natural gas price perspective, FPL's customers appear to be similarly situated after the retirement of Scherer Unit 4 and, in fact, better off as more solar is added to the system.

Finally, Mr. Smith expresses interest in whether FPL pursued a sale of the unit to Georgia Power. FPL did pursue other alternatives to retirement, including a sale of its share of Scherer Unit 4. There was very limited interest from the market and the resulting economics of a sale would have paled by comparison to the retirement scenario being presented herein.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Kathleen Slattery was inserted.)

ERRATA SHEET

WITNESS: **KATHLEEN SLATTERY – DIRECT TESTIMONY AND EXHIBIT KS-3**

PAGE #	**LINE #**	**CHANGE**
15	15	Change “$1,440” to “$1,439”
16	8	Change “$1,266” to $1,270”
21	2	Change “$109,181,000” to “$109,656,000” and “$110,751,000” to “$111,250,000”
	4	Change “($88,366,000)” to “($88,482,000)” and “($97,679,000)” to “($97,832,000)”
	5	Change “$9,006,000” to “$9,018,000” and “$12,367,000” to “$12,386,000”
	6	Change “$42,759,000” to “$42,816,000” and “$44,046,000” to “$44,116,000”
	8	Change “($36,601,000)” to “($36,649,000)” and “($41,266,000)” to “($41,331,000)”
	9	Change “$96,156,000” to “$96,127,000” and “$99,248,000” to “$99,217,000”
	10	Change “$168,736,000” to “$169,134,000” and “$168,733,000” to “$169,136,000”
21	21	Change “$12” to “$13”
23	13	Change “2.1” to “2.2”
28	2	Change “2.1” to “2.2”
Exhibit KS-3, Page 1 of 2		Replace with the attached corrected page

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF KATHLEEN SLATTERY

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Kathleen Slattery. My business address is Florida Power & Light Company, 700 Universe Boulevard, Juno Beach, Florida 33408-0420.

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

A. I am employed by Florida Power & Light Company ("FPL" or "Company") as the Senior Director of Executive Services and Compensation.

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

A. I am responsible for the overall design and administration of all compensation programs and management of executive benefits and services. I share responsibilities with a peer for the Company's total rewards strategy and programs.

Q. Please describe your educational background and professional experience.

A. I am a Florida native and attended Florida State University, where I earned a Bachelor of Science and a Juris Doctor degree. I have been a member of the Florida Bar since 1992. Before joining FPL, I worked in labor relations and served as a trustee of two outside electrical worker unions' pension and health and welfare funds. I began working at FPL in 1996 as a benefit plan administrator and have held various positions of increasing responsibility in Human Resources ("HR") since that time. My experience at FPL has included qualified and non-qualified benefit plan design and administration, salary and incentive compensation plan design and administration, and legal compliance of such plans and programs. I have extensive knowledge of FPL's compensation and benefits philosophy, its HR plans and practices, and its payroll system. As part of my responsibilities, I regularly rely on surveys and reports produced by third party organizations to stay abreast of trends in compensation and benefits throughout the utility industry and other businesses with which FPL competes for talent.

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring the following exhibits:

- KS-1 Consolidated MFRs Sponsored or Co-sponsored by Kathleen Slattery
- KS-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-Sponsored by Kathleen Slattery
- KS-3 Total Salaries & Wages
- KS-4 Position to Market (2020 Base Pay)
- KS-5 Merit Pay Program Awards
- KS-6 Total Benefit Program
- KS-7 Active Employee Medical Plan
- KS-8 Average Medical Plan Expense Per Employee
- KS-9 Pension & 401(k) Employee Savings Plan

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. Yes. Exhibit KS-1 lists the consolidated MFRs that I am sponsoring and co-sponsoring.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. Yes. Exhibit KS-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. In my testimony, references to "FPL" will mean FPL and Gulf consolidated, except where I specifically state "FPL standalone," which shall mean FPL excluding Gulf.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an overview of the gross payroll and benefit expenses shown in MFR C-35 and to demonstrate the reasonableness of FPL's forecasted payroll and benefit expenses.

Q. Please summarize your testimony.

A. FPL designs and manages its compensation and benefits programs as elements of a total rewards package. In order to address changing workforce dynamics, to control costs, and to attract, retain, and engage the required workforce, FPL places more focus on flexible, performance-based variable compensation than on less flexible, fixed-cost compensation and benefit programs. This focus has allowed the Company to react to market conditions and drive the superior performance documented by other FPL witnesses, while managing total program costs.

FPL's total rewards costs included in the forecast for purposes of the 2022 Test Year and 2023 Subsequent Year are reasonable and do not include any types of expense that the Commission has not previously approved for recovery. FPL's gross total compensation and benefits in 2022 and 2023 are projected to be $1,563 million and $1,608 million, respectively. Comparison of FPL's compensation and benefits programs against relevant industry benchmarks demonstrates that both compensation and benefits, while very competitive, are generally below the market value of benchmarked utility and general industry companies. The Company has diligently managed costs both to engage employees and provide value to customers.

The total rewards package, emphasizing pay for performance, has served the Company and its customers well. FPL has successfully provided value to its employees and its customers through efficient use of compensation and benefits to drive a culture that rewards improved efficiency and performance. FPL's performance-based compensation program has been and continues to be a key factor in FPL's ability to achieve the exceptional performance and efficiencies described in FPL witness Reed's testimony. As FPL moves forward, it must continue to provide a competitive total rewards package to its employees in order to attract and retain the necessary talent. The projected levels of total compensation and benefits expense for 2022 and 2023 are reasonable and necessary to serve FPL's customers and to attract and retain the caliber of employees that create a high-performance organization and deliver superior value for customers.

II. THE OBJECTIVES OF FPL'S TOTAL COMPENSATION AND BENEFITS

Q. What are the objectives of FPL's compensation and benefits programs?

A. There are several key objectives of FPL's compensation and benefits approach. The Company designs its compensation and benefits program to attract, retain, engage and competitively reward its employees based on national and local comparative markets. FPL's compensation program also reflects a pay-for-performance philosophy, linking total compensation to attainment of corporate, business unit, and individual goals such as excellent reliability and customer service. In addition, FPL's compensation and benefits approach is designed to control fixed costs by placing greater emphasis on variable cash compensation rather than on the traditional programs that are not performance-based, such as long-term retirement benefits. Finally, the Company strives to manage its various compensation and benefits programs holistically in order to keep its total program expenses at a reasonable level. FPL continuously monitors and benchmarks the compensation and benefits components of the total rewards package. This ensures that the total program is in line with the median of the combined compensation and benefits programs of the appropriate comparator groups.

Q. What is FPL's total compensation philosophy?

A. FPL's philosophy has been, and continues to be, to provide competitive, market-based salaries with consideration of an individual's performance and contribution to the Company's key goals. The performance-based pay programs have enabled FPL to develop a culture of employee commitment and ownership in the performance of the Company. Each salaried employee's compensation has a portion of pay that is variable. The variable pay is linked to individual, business unit and corporate objectives that benefit our customers, including budget goals and operating efficiency milestones such as plant availability, service reliability, and quality of customer service. The strategic emphasis on the variable pay program, rather than fixed salary and benefits costs, encourages performance at an individual employee level and adds flexibility in recognizing that performance.

Q. How has FPL designed and managed its compensation and benefits programs to achieve these objectives?

A. FPL's approach to the design and management of compensation and benefits is to consider them as elements of one total rewards package. Since 1997, when the Company converted its pension plan to a cash balance plan and eliminated post-retirement medical coverage for all new hires, the total rewards package has been less focused on fixed-cost benefit programs and more focused on performance-based variable cash compensation. Then, over the past decade, due to rising health care costs, FPL made controlling those costs a key strategic initiative, and also designed health plans that require employees to consider more carefully when and where they pay for health and healthcare services for themselves and their family. This has allowed FPL to mitigate the rate of increases in program costs for the Company and the employees. FPL's strategic decisions to control benefit program costs and to develop and emphasize a pay-for-performance compensation program has been an important tool in the Company's ability to achieve efficiency, reliability, and customer service improvements over the past nearly quarter-century, all of which contribute to FPL's ability to deliver superior value for its customers. Moreover, the flexibility provided by these strategic changes has been an essential component of the Company's success in dealing with the workforce challenges confronting the utility industry.

III. INDUSTRY CHALLENGES

Q. Please describe the challenges faced by the utility industry and FPL in attracting, retaining, and engaging a diverse workforce with the required skills.

A. FPL and other utility industry employers are striving to adapt to the changing skills needs resulting from rapid technological advancement. The Global Energy Talent Index ("GETI") is an annual energy industry recruitment and employment trends report published by Airswift and Energy Jobline, a job site for the energy and engineering industries. Based on 17,000 survey responses, the 2019 GETI report stated that nearly half of respondents in the industry are worried about a looming talent crisis in the sector. Sixty-two percent believed the crisis would hit within five years—by 2023—and 32 percent thought it already had arrived. Engineering was the discipline cited most commonly as an area of concern. In the 2020 U.S. Energy Employment Report, published jointly by the National Association of State Energy Officials and the Energy Futures Initiative, 93 percent of utility employers in electric power generation reported that it was either somewhat difficult or very difficult to hire new employees (an increase of 30 percentage points over the prior year). The utility industry identifies technicians or mechanical support, engineers/scientists, and electrician/construction workers as the top occupations for hiring difficulty. Electric power generation employers noted that the hiring difficulty is driven by a lack of experience, training and technical skills. There are several key factors creating the shortage of skilled workers:

(1) <u>Aging Workforce and Need for More Skilled Replacement Workers:</u> The aging of the electric utility industry workforce has been a concern of government and industry leaders for some time. The Center for Energy Workforce Development ("CEWD"), a non-profit consortium, was formed in 2006 to help utilities work together to develop solutions to the upcoming workforce shortage in the industry. The CEWD Gaps in the Energy Workforce 2019 Pipeline Survey states that 33 percent of the utility workforce are Baby Boomers, born between 1946 and 1964, nearing retirement. Additionally, it notes that while the age of the workforce has stabilized due to an increase in

younger workers, the younger workers attrit at a higher rate than their older predecessors, leaving for jobs both within and outside the industry after fewer years of service than older peers. The increased rates of retirement and attrition have resulted in a shortage of available workers with the requisite qualifications and skills to replace them. A separate study, the 2019 CEWD Southeast Energy Workforce Demand report, also emphasized the growing impact of retirement and attrition. CEWD was initially focused solely on the aging workforce issue and efforts to recruit youth, women, minorities and veterans to the industry, but now dedicates equal attention to helping utilities upskill the workforce and prepare employees for dynamic energy careers as the industry faces rapid changes in technology.

(2) Demands of Emerging Technologies: The growing demand for renewable generation and energy storage solutions, the smart grid operating model, and digitalization are creating additional demand for skilled and tech-savvy workers and will further impact the skills shortage. Emerging technology is placing a greater focus on engineering, information technology, distribution resources, and customer interaction. HR professionals talk about "hot skills" and "hot jobs" to describe when new technologies and business models create a demand for skilled talent that outstrips the labor supply. Scarcity often happens when a new demand for particular skill sets emerges in the market, such as cybersecurity, data scientists and engineers with cloud computing skills. For example, a research report released by Emsi, a national labor analytics firm,

states the U.S. has less than 50 percent of the trained workers needed to meet the demand for cybersecurity professionals, making recruiting for these roles very challenging.

Q. To what extent have these industry challenges impacted FPL's efforts to attract and retain the necessary workforce?

A. FPL is facing similar workforce challenges as other electric utilities. Currently, 31 percent of FPL's workforce is eligible to retire, and an additional 11 percent of the current FPL workforce is projected to be retirement-eligible in five years. In addition, in the generation and power delivery business units, the numbers are slightly higher, with 33 percent eligible to retire now and an additional 10 percent eligible to retire in five years. FPL has programs to upskill its existing workforce to learn emerging technologies and new leadership and project management skills, but it still must go to the competitive labor market for external hires due to retirements and other turnover. FPL's total annual turnover rate is usually about seven percent. FPL typically hires about 680 new employees each year, and it is becoming more difficult to find candidates with the advanced technical skills we need to support our culture of innovation and continuous improvement.

Clearly, there are a number of factors driving the skills shortage in the utility industry and challenging FPL's and other companies' ability to attract and retain the required workforce. Although the industry and educational institutions have recognized the challenges and started to address future skills demands, in the short term, the factors discussed above are creating competition for skilled resources and applying pressure on compensation levels. Moreover, most of the key technical and engineering positions cannot be filled from the local labor pool, so FPL must remain competitive in national as well as local markets.

Q. Has FPL taken any steps to build its talent pipeline to ensure it can successfully obtain the necessary future workforce?

A. Yes. FPL has created a robust summer internship program providing participants with rewarding learning experiences. Successful participants are provided post-graduation full-time job offers at the end of the internships. Through its college recruiting programs, FPL also hires pools of graduating engineers twice per year to continue to grow the organization's engineering talent.

Q. Has FPL focused on diversity of its hires, and building a diverse talent pipeline?

A. Yes. FPL is strongly committed to diversity and inclusion, as recognized by Forbes in its inclusion of our company on its list of America's Best Employers for Diversity; FPL's parent company is one of only 500 employers to receive this honor across the U.S. and has been included on Forbes' list each year since its creation in 2018. We recruit students from more than 60 colleges including Historically Black Colleges and Universities ("HBCU"). FPL focuses on diversity recruiting through a variety of partnerships including HBCUConnect, National Society of Black Engineers, Black Data Processors, Women in

Technology and many more. In summary, through our college relationships, organization partnerships and active sourcing and recruiting, the FPL recruiting team is able to create a broad and diverse pipeline of talent for current and future open positions.

Q. To what extent has the COVID-19 pandemic impacted FPL's efforts to attract and retain the necessary workforce?

A. FPL has continued to recruit talent throughout the pandemic; however, it has been challenging to secure qualified talent for a number of reasons. Interviewing, on-boarding and training using web conferencing, rather than in person, have been challenging for all parties.

When we do fill vacant positions, our candidate pools are not helped by pandemic-related unemployment because the impact of the pandemic is largely industry-specific, with significant layoffs occurring in industries where skills are not easily transferrable to utilities. According to the U.S. Bureau of Labor Statistics, the largest 12-month increases in number of unemployed persons have been in leisure and hospitality services and wholesale and retail trades, where skills are not transferrable to most utility jobs.

Q. How has its total rewards strategy helped FPL to respond to current and future workforce challenges?

A. As a result of its total rewards strategy, which emphasizes competitive performance-based compensation over fixed-cost benefits, FPL is better positioned than most other utilities to compete for qualified candidates in the market. Job applicants concentrate more attention on compensation than on benefits when considering an opportunity. Benefits cost management has allowed the Company to better focus on the elements of the total rewards package that have more value for attraction, retention, and engagement of the required workforce, specifically variable performance-based pay. FPL is not nearly as burdened as other utilities with the considerable cost of pension and post-retirement medical obligations. FPL also has better managed the rising costs of health care relative to its peers.

IV. REASONABLENESS OF FPL'S TOTAL COMPENSATION

Q. What are FPL's gross total compensation costs for the projected 2022 Test Year and the 2023 Subsequent Year?

A. FPL's gross total compensation cost, represented as Gross Payroll on MFR C-35, is projected to be $1,394 million for the 2022 Test Year and $1,440 million for the 2023 Subsequent Year.

Q. Is FPL seeking recovery for all compensation expense in 2022 and 2023?

A. No. FPL has excluded from its expense request the portions of executive and non-executive incentive compensation that were excluded by the 2010 Rate Order, Order No. PSC-10-0153-FOF-EI. While our filing reflects our decision not to revisit this issue at this time, we continue to believe these expenses are necessary and reasonable, a critical component of FPL's cost of service, a significant driver behind FPL's outstanding performance, and properly recoverable in rates. They are effective tools in attracting, retaining and engaging our workforce, and play a significant role in delivering value to customers.

Q. How will FPL's total compensation cost change from 2019 to 2022, and is the cost reasonable?

A. For the period from 2019 to 2022, FPL's total compensation or gross payroll expense is forecasted to increase on average about three percent per year, from $1,266 million to $1,394 million. About three percent per year is also the market median salary increase for 2019 through 2021 from WorldatWork, a professional association that sets the standard in the field of total rewards and produces the leading annual global compensation planning and salary increase survey. Gross payroll as represented on MFR C-35 includes all wages and salaries, overtime pay, premium pay and miscellaneous other earnings. It also includes those costs that ultimately are allocated to other subsidiaries as well as the aforementioned incentive compensation costs that FPL is not seeking to recover. As described earlier in my testimony, it is critical that FPL's compensation remain competitive to ensure we can attract talent at all levels of the organization, particularly those with the advanced technical skills we need from a market that is experiencing scarcity of workers with these skills.

From 2019 to 2022, gross payroll per employee is projected to increase by about three percent per year, which is in line with the WorldatWork salary increase factor of three percent per year.

The projected growth in compensation cost from the 2022 Test Year to the 2023 Subsequent Year is also reasonable. Gross payroll from 2022 to 2023 is projected to increase by $45.5 million, about three percent, which is in line with the WorldatWork inflation factor.

Q. How does FPL's gross payroll cost compare with that of other utilities?

A. FPL's total compensation cost compares very favorably to that of other utilities as demonstrated by review of Federal Energy Regulatory Commission Form No. 1 report data. FPL has reviewed its total compensation cost and compared it to that of other comparable utilities. The companies in the comparison included other regional utilities as well as other vertically integrated utilities of similar size. As shown on Exhibit KS-3, FPL continues to be one of the more efficient utilities from a total compensation standpoint. This efficiency is particularly evident when one looks at total compensation – whether on a per-customer or megawatt hour basis.

Q. What resources does FPL use to evaluate its compensation program?

A. FPL uses a variety of compensation survey resources to evaluate its program. These resources include regional data but are primarily national compensation surveys, because the Company's recruiting department searches nationally for personnel to fill managerial, professional, and technical positions. Most of the key technical and engineering positions cannot be filled from the local labor pool, so FPL must remain competitive in national as well as local markets. FPL utilizes nationally recognized third-party compensation survey sources to aggregate and assess comparative data from other national and regional employers, both in general industry and the utility industry. It is important to utilize both general and utility comparative market information, since FPL's workforce encompasses multi-industry talents. FPL utilizes several information sources for compensation survey data, including:

- Willis Towers Watson, an international human resources consulting firm;
- Mercer, LLC, an international human resources consulting firm;
- Aon, an international human resources consulting firm; and
- WorldatWork, a global human resources association of more than 70,000 compensation, benefits and human resources professionals.

Q. How does FPL's base compensation program compare to the market?

A. FPL's base pay levels are comparable to the rates paid by its competitors (generally companies of similar size, scale, and complexity) for employees performing similar jobs and with similar skill sets. FPL performs a detailed annual benchmarking analysis of its base pay rates to determine "position to market." The most recent market analysis completed in 2020 included market survey data from approximately 37 sources, including Willis Towers Watson, Aon, and Mercer. Exhibit KS-4 demonstrates that, as of the date of this latest study, FPL has maintained its median base pay, in the aggregate, below the median or 50th percentile, specifically 3.8 percent below median for salaried employees and 2.7 percent below median for hourly employees.

Q. Please describe FPL's annual performance-based merit program.

A. There are two components to FPL's annual performance-based merit program. The first component is a merit award determined by an individual's performance level and salary position relative to market. The second component is a variable pay program that provides a payment based on each individual's contribution as well as Company and business unit results in comparison to pre-established objectives. FPL's variable compensation is awarded based on an individual's contribution to corporate, business unit, and individual performance indicators. These performance indicators include controlling customer-related costs and operating efficiency milestones such as plant availability, service reliability, and quality of customer service.

Q. How do FPL's annual pay increase program and variable pay awards compare to market?

A. FPL regularly benchmarks its annual pay increase program and variable pay awards against relevant market data. As shown in Exhibit KS-5, FPL's annual pay program, including merit base increases and variable incentive pay awards, has been at or below market for the period from 2018 through 2020, while remaining competitive.

Q. In the event the Commission does not approve FPL's request to unify FPL and Gulf base rates, have you calculated projected total compensation or

gross payroll expenses for FPL and Gulf as separate ratemaking entities using the same considerations that you described earlier?

A. Yes. As shown on FPL Supplemental Schedule C-35, projected gross payroll for standalone FPL are $1,306 million for the 2022 Test Year and $1,351 million for the 2023 Subsequent Year. As Shown on Gulf Supplemental Schedule C-35, projected gross payroll for standalone Gulf are $94 million for the 2022 Test Year and $96 million for the 2023 Subsequent Year.

V. BENEFITS

Q. Please describe FPL's benefits package.

A. Again, FPL's benefits program is designed and managed as part of the total rewards package. The benefits package includes a full complement of benefits, comprised of three primary components: health and welfare benefits, retirement plans, and various benefits required by law.

Q. What are FPL's projected benefits costs for the 2022 Test Year and 2023 Subsequent Year?

A. Total benefits costs are projected to be $169 million in 2022 and $169 million in 2023, the major components of which are as follows:

	2022	2023
• Health and welfare benefits	$109,181,000	$110,751,000
• Retirement benefits		
o Pension plan	($88,366,000)	($97,679,000)
o Post-employment benefits	$9,006,000	$12,367,000
o Employee savings plan	$42,759,000	$44,046,000
• Total Retirement Benefits	($36,601,000)	($41,266,000)
• Benefits required by law	$96,156,000	$99,248,000
Total Benefits Cost	$168,736,000	$168,733,000

Benefits required by law include Social Security and Medicare tax, federal and state unemployment taxes, and workers' compensation.

Q. In the event the Commission does not approve FPL's request to unify FPL and Gulf base rates, have you calculated projected total benefits expenses for FPL and Gulf on a standalone basis using the same considerations that you described earlier?

A. Yes. As shown on FPL Supplemental Schedule C-35, projected total benefits expense for standalone FPL are $158 million for the 2022 Test Year and $157 million for the 2023 Subsequent Year. As shown on Gulf Supplemental Schedule C-35, projected total benefits expense for standalone Gulf are $12 million for the 2022 Test Year and $12 million for the 2023 Subsequent Year.

Q. How does FPL evaluate the design and cost of its benefit plans, and how do the plans compare to those of other companies?

A. FPL uses the Aon Benefit Index, an actuarial tool that compares the value of benefit plans. Aon is an internationally recognized benefits consulting firm that provides analysis and consultation on the competitiveness of participating companies' benefit programs and produces the Aon Benefit Index. The study methodology first analyzes the value of each benefit plan for each individual in the plan and then converts the individual values to a composite value for the entire employee population by applying a standard set of actuarial and employee participation assumptions. The index base point of 100.0 is set as the average of the values of the base companies selected for the comparison. Index values below 100.0 indicate that a company is being more successful than average in managing plan design as a means of controlling benefits cost. FPL has used the Aon study to compare its benefits programs to those of companies in the general industry and utility industry sectors, and to those of Fortune 500 companies participating in the study.

Exhibit KS-6 displays the relative value of FPL's total benefits program for 2020 compared to a base utility comparator group composed of 13 electric utilities that are most similar to FPL in terms of revenue and workforce composition or that are Florida-based. The graph also displays relative value comparisons to a broader utility group (composed of the 13 utilities that participated in the survey), to a general industry grouping, and to Fortune 500 companies that participated in the study. The graph shows that FPL's Benefit Index for the total benefit program is below average compared to the base utility comparator group and each of the other industry groupings. FPL's total benefits program rated 86.7 as compared to a 100 when averaging the 13 utilities in the base utility comparator group and to a 98.4 average for the broader utility group and 91.4 average for Fortune 500 companies. These results are consistent with the Company's objective to emphasize performance-based variable cash compensation over traditional long-term benefits, which helps keep costs low and drives superior performance for the benefit of customers.

Q. What is FPL's projected medical cost for the 2022 Test Year?

A. FPL's projected medical cost is $91 million for active employees in the 2022 Test Year. As shown on MFR C-35, this represents an increase of $2 million or just 2.1 percent between 2019 and 2022. This is below the 4.3 percent projected increase in CPI and significantly below the utility industry health care trend of a 12.5 percent increase between 2019 and 2022.

Q. What is FPL's projected medical cost for the 2023 Subsequent Year?

A. FPL's projected medical cost is $93 million for active employees in the 2023 Subsequent Year as shown on MFR C-35, which represents an increase of $1 million or 1.6 percent from 2022. This compares to an increase of 5.5 percent in the utility industry health care trend, as forecast by Aon, over the same time frame.

Q. In the event the Commission does not approve FPL's request to unify FPL and Gulf base rates, have you calculated projected medical cost for FPL

and Gulf as separate ratemaking entities using the same considerations that you described earlier?

A. Yes. As shown on FPL Supplemental Schedule C-35, projected medical cost for standalone FPL is $84 million for the 2022 Test Year and $85 million for the 2023 Subsequent Year. As shown on Gulf Supplemental Schedule C-35, projected medical cost for standalone Gulf is $7 million for the 2022 Test Year and $7 million for the 2023 Subsequent Year.

Q. How does FPL determine the plan design of medical benefits for each year?

A. FPL's benefits department reviews trends in health care claims as well as plan designs and programs available across various industries, to determine the optimal plan design and pricing structure that will provide competitive, cost-effective benefits for all employees.

Q. How does FPL's medical plan compare to industry standards?

A. The relative value of FPL's medical plan for active employees is below average when compared to other utility and general industry companies participating in the 2020 Aon Benefits Index. As illustrated by Exhibit KS-7, FPL's plan had a relative value of 89.6 as compared to the average of 100 for the 13 utilities in the base utility comparator group and the broader utility group. FPL's relative value for active medical is also below both the general industry and Fortune 500 company averages.

Q. How do FPL's projected medical costs per employee compare to those of other utilities and the national average?

A. FPL tracks medical plan expense per employee on an ongoing basis as a means of comparing its costs to those of other companies. Exhibit KS-8 illustrates FPL's medical plan expense per employee for 2016 to 2020 and the projected cost for 2021 as compared to the utility industry benchmark. FPL's average expense per employee has remained below the utility industry average from 2016 to 2020 and is projected to remain below the industry average in 2021, as illustrated in Exhibit KS-8. The increases in FPL's health care plan expense per employee for 2016 through 2020 have been below the utility industry trend reported by Aon. Furthermore, Aon's forecasted utility industry benchmark for 2021 is approximately 27 percent above FPL's projected medical plan expense per employee in 2021.

Q. What specific initiatives has FPL pursued to successfully control health care costs?

A. FPL has made health care cost control a key strategic initiative, applying a continuous improvement process to develop an integrated health strategy that will optimize health and wellness for employees and control costs for both the Company and employees. FPL's ability to keep per employee health care costs below the utility industry benchmarks and to project that costs will remain below the utility industry benchmarks in 2021 and beyond have been the direct result of aggressive management of the drivers of health care costs. The

Company's successful cost control strategy has relied upon a variety of initiatives, including:

- Plan design featuring choice, price incentives and on-line comparison tools to encourage cost-effective plan selections;
- Implementation of mobile on-demand telehealth option to drive down provider costs;
- Comprehensive health promotion together with implementation of wellness incentives to encourage preventative care and utilization and care management programs;
- Providing access to centers of excellence and second opinion services for higher quality and lower cost care;
- Dependent eligibility audits and per dependent pricing to align cost of coverage with benefit received and spousal/adult surcharges to prevent unnecessary coverage;
- Aggressive vendor management and contracting, including disaggregation of medical administration and associated networks;
- Aggressive specialty pharmacy management and an online tool identifying pharmacy savings to encourage use of more cost-effective drugs; and
- Implementation of retiree prescription drug coverage through Medicare program.

Q. Are there other initiatives FPL has taken that have contributed to the successful management of health care costs?

A. Yes. A key long-term cost control initiative has been the creation of a healthy work environment and the aggressive promotion of the employee's personal responsibility for his or her own health, as evidenced by the Company's comprehensive health and well-being programs. FPL's comprehensive health and well-being programs, developed over the past 30 years, have led to reductions in health risk factors for the employees who have participated in them, which will benefit our employees through better health and our customers through lower plan cost in the 2022 Test Year and 2023 Subsequent Year and beyond.

Q. Has FPL received recognition for successful management of its health care programs and costs?

A. Yes. The effectiveness of the programs has been acknowledged through frequent national recognition, including "Best Employers for Healthy Lifestyles" Awards from the National Business Group on Health for thirteen of the last sixteen years.

Q. What are FPL's expectations for the rate of increase in medical costs?

A. Aon is forecasting utility industry health care cost increases of approximately 5.5 percent from 2021 to 2022, driven by a number of factors: the aging population, the growing burden of chronic diseases, various federal and state mandates, an increase in utilization and costs of prescription drugs including specialty drugs, hospital/provider consolidations, and enhancements in medical technology that will increase utilization. As previously stated, FPL's medical cost is estimated to increase just 2.1 percent between 2019 and 2022. Thus, while FPL has been successful in mitigating total medical costs and in managing per-employee medical costs below the utility industry average, rising health care costs continue to be a concern going forward. However, as noted previously, for purposes of the rate request in this case, FPL projects medical costs of $91 million, representing a significant achievement in cost mitigation and remarkable achievement within the industry.

Q. How has FPL's successful management of its health care program and costs been a benefit to customers?

A. As I mentioned previously, the Company has maintained both total program costs and per employee medical costs well below Aon's reported health care cost trends. This success in controlling medical costs reduces the Company's revenue requirements, which is a direct benefit to customers.

Q. Does FPL offer retirement plans to employees, and is that consistent with industry practices?

A. Yes. FPL offers its employees retirement plans consisting of a pension plan and a 401(k) employee savings plan, as do approximately 39 percent of the utility industry comparator group included in the 2020 Aon Benefit Index. The Company also provides post-employment medical, life, and disability benefits; however, as discussed previously, the post-employment medical and life benefits were discontinued for employees hired on or after April 1, 1997.

Q. Has FPL done anything recently to control the costs within its retirement plans?

A. Yes. Within the post-employment medical benefits a change was introduced to provide prescription drugs through Medicare which enabled FPL to take advantage of prescription drug subsidies. This change reduced post-employment liabilities by $66.2 million which accounting standards require be amortized over about five years (2017 – 2022) as a reduction in operations and maintenance expense. The lower liability going forward also yields further annual savings of $2.4 million in operations and maintenance expense.

Q. What is FPL's projected retirement expense in the 2022 Test Year?

A. The projected expense for the 2022 Test Year is a credit of $37 million. This is the net result of the pension plan credit of $88 million that is partially offset by the 401(k) employee savings plan expense of $43 million and the post-employment medical, life, and disability benefits expense of $9 million.

Q. What is FPL's projected retirement expense in the 2023 Subsequent Year?

A. For the 2023 Subsequent Year, FPL's projected retirement expense is a credit of $41 million, the components being a pension plan credit of $98 million partially offset by expenses of $44 million for the employee savings plan and $12 million for post-employment medical, life, and disability benefits.

Q. Why are the retirement expense and the employee pension benefit reflected as a credit?

A. The assets of the pension plan have been beneficially invested such that the fair value of the assets exceeds the actuarially determined projected obligation. The size of the pension plan credit is sufficient to offset the employee savings plan and post-employment benefit expenses -- thus the net credit for retirement expense.

FPL's pension benefit is calculated based on Financial Accounting Standards Board ("FASB") Codification, ASC 715, which covers retirement benefits. Whereas many utilities must recover from customers a pension cost associated with providing a retirement plan to its employees, FPL has, through prudent plan design decisions and asset investment over time, been able to grow its pension assets at a faster rate than the costs of its plan obligations. Even after the major market correction, the pension trust still exceeds its obligations and, therefore, creates a negative expense (a credit) to the benefit of customers.

Q. How do FPL's retirement plans compare to the industry?

A. As shown in the Aon Benefit Index's comparison chart (Exhibit KS-9), FPL's retirement plans are valued at 79.5, well below the averages of the 13 comparator companies and the utility industry (100 for the comparator and 94.4 for the overall utility industry).

Q. Does this evaluation demonstrate the reasonableness of FPL's qualified retirement plans?

A. Yes. FPL provides both a pension and 401(k) employee savings plan to its employees in order to attract and retain high quality employees. However, through careful management of the plans, FPL has been able to keep their relative value considerably below the average of the utility industry as demonstrated by the Aon Benefits Index (Exhibit KS-9).

Q. Please summarize your testimony concerning FPL's total compensation and benefits costs for 2022 and 2023.

A. With its emphasis on pay for performance, FPL's total rewards package has served the Company and its customers well. The Company has made good progress in controlling costs, and the total compensation and benefits costs are very competitive when measured against relevant benchmarks (as demonstrated on Exhibits KS-3 through KS-9). The 2022 and 2023 projected levels of compensation and benefits expense are reasonable and necessary to attract and retain the caliber of employees that create a high-performance organization.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Kathleen Slattery was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF KATHLEEN SLATTERY

DOCKET NO. 20210015-EI

JULY 14, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kathleen Slattery, and my business address is Florida Power & Light Company ("FPL" or "the Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

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

A. Yes. I am co-sponsoring the following exhibits:

- LF-10 – FPL's Notice of Identified Adjustments filed May 7, 2021 and Witness Sponsorship, filed with the rebuttal testimony of FPL witness Fuentes.
- LF-11 – FPL's Second Notice of Identified Adjustments filed May 21, 2021 and Witness Sponsorship, filed with the rebuttal testimony of FPL witness Fuentes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to rebut the direct testimony of Office of Public Counsel ("OPC") witness Ralph Smith regarding executive and non-executive incentive compensation expense, and expense associated with FPL's incentive program for project development and management. Specifically, I will respond to OPC witness Smith's concerns as to whether the amounts FPL included for executive and non-executive incentive compensation expense are consistent with the Florida Public Service Commission's ("Commission") Order No. PSC-10-0153-FOF-EI ("2010 Rate Case Order"). Additionally, I will respond to OPC witness Smith's recommendation that the amounts included for the employee incentive program related to project development and management should be capitalized as construction project costs rather than expensed as operations and maintenance ("O&M").

Q. Please summarize your rebuttal testimony.

A. FPL's projected compensation and benefits expense is reasonable and prudent, and no intervenor has filed testimony stating otherwise. My rebuttal testimony demonstrates that FPL has excluded from its expense requests for 2022 and 2023 the portions of executive and non-executive incentive compensation that were excluded by the Commission in the 2010 Rate Case Order. I also validate that it is appropriate to include the costs associated with the employee incentive program for project development and management in FPL's forecasted expense for 2022 and 2023, as no Company capital is deployed in the related projects. It is noteworthy that no intervenor witness has questioned, in any way, the reasonableness or prudence of FPL's underlying performance-based incentive programs.

II. EXECUTIVE AND INCENTIVE COMPENSATION

Q. OPC witness Smith questions whether FPL's adjustment for executive and non-executive compensation is consistent with the 2010 Rate Case Order. Has FPL excluded from its expense requests for 2022 and 2023 the portions of executive and non-executive incentive compensation that were excluded by the Commission in the 2010 Rate Case Order?

A. Yes. Based on the executive compensation adjustment information reflected on MFR C-3 and Exhibit LF-10, FPL has excluded from expense $51.250 million (jurisdictional) in the 2022 Test Year and $54.028 million (jurisdictional) in 2023 Subsequent Year. In addition, FPL's revenue requirement calculation includes an adjustment to remove capitalized executive incentive compensation from plant in-service consistent with the 2010 Rate Case Order. As reflected on MFR B-2, the jurisdictional rate base adjustment is $54.120 million for 2022 Test Year and $56.699 million for 2023 Subsequent Year. There is no additional adjustment to be made.

Q. Which portions of executive and non-executive incentive compensation are excluded?

A. All executive incentive compensation is excluded. For non-executive stock-based incentive compensation, 50% of restricted stock and target performance share awards are excluded, as well as 100% of any expense above target for performance shares.

Q. Has FPL consistently reported the exclusion of these portions of executive and non-executive incentive compensation from net operating income on its earnings surveillance reports to the Commission since 2010?

A. Yes. FPL has provided monthly earnings surveillance reports to the Commission since 2010 that have consistently reflected the exclusion of these portions of incentive compensation from net operating income.

Q. Has FPL made any changes to its methodology for calculating this incentive compensation exclusion from net operating income since it began to calculate such exclusion in 2010?

A. No. FPL has been consistent in its methodology since 2010.

Q. Was this same methodology for calculating the executive and non-executive incentive compensation adjustment from net operating income also applied by FPL to its revenue requests in the 2012 and 2016 Rate Cases, Docket Nos. 20120015-EI and 20160021-EI?

A. Yes. FPL's minimum filing requirements and testimony in the 2012 and 2016 Rate Cases reflected revenue requests which adjusted the same portions of executive and non-executive incentive compensation that were excluded by the 2010 Rate Case Order. These adjustments were calculated using FPL's consistent methodology since 2010.

Q. Please explain why the current adjustment is only slightly more than the adjustment in 2010.

A. Although OPC witness Smith states that the current adjustment is $47.859 million, FPL has actually excluded from expense $51.250 million (jurisdictional) in the 2022 Test Year and $54.028 million (jurisdictional) in 2023 Subsequent Year, after factoring in the executive compensation adjustment reflected on Exhibit LF-10.

Additionally, the 2010 Rate Case Order cited an adjustment figure of $48.453 million that was calculated from gross compensation figures, before removal of compensation costs allocated to affiliates. Therefore, the adjustment figures in the 2010 Rate Case Order were overstated. As a result, the figure of $48.453 million in the 2010 Rate Case Order should have reflected allocation of costs to affiliates, reducing the disallowance to approximately $35.461 million.

Finally, it is important to note that while compensation increases at market rates over time, at FPL there were counter-pressures to such increases. FPL streamlined its senior management team over the past 12 years, eliminating seven executive positions and downshifting the work of an additional six executive positions to a lower level. FPL thereby avoided costs while maintaining superior service levels to its customers through these functional consolidations.

Q. Has any intervenor witness questioned the prudence or reasonableness of any aspect of FPL's executive or non-executive incentive compensation programs?

A. No. Not a single intervenor witness has commented in any way on FPL's program design or compensation levels.

III. INCENTIVE PROGRAM RELATED TO PROJECT MANAGEMENT

Q. Has FPL included in O&M expense in the 2022 Test Year and 2023 Subsequent Year an employee incentive program related to project development and management that references "construction"?

A. Yes. FPL has included an employee incentive program that provides recognition and compensation to a small number of FPL project developers, engineers, and project managers who achieve pre-established goals related to construction projects undertaken by large commercial customers.

Q. Has OPC witness Smith questioned the prudence or reasonableness of this program?

A. No. OPC witness Smith has not raised any objections to the program itself — neither the design nor the total cost. Rather, OPC witness Smith only questions whether the amounts for the employee incentive program related to project development and management should be expensed as O&M or treated as capital construction project costs.

Q. Please explain why the costs associated with this employee incentive program are appropriately included as O&M expense in the 2022 Test Year and the 2023 Subsequent Year.

A. These costs should remain in O&M expense because the projects do not involve any deployment of Company capital, but instead involve large commercial customers engaging FPL engineers and project managers to work with them to design improvements to the customers' facilities. These projects involve deployment of the customers' own capital dollars on their property for conservation and other improvements that will facilitate considerable savings to the customers over time. FPL provides a turnkey service to these commercial end-use customers, such as schools, hospitals, municipalities, etc. FPL employees design projects that meet customer needs, model the projected savings over time, and oversee implementation. No FPL capital is deployed so compensation costs are expensed, as is appropriate.

IV. CONCLUSION

Q. Should any incentive compensation expense not already adjusted by FPL in its filing be removed from the 2022 Test Year or 2023 Subsequent Year O&M request?

A. No. FPL has already excluded from its expense requests for 2022 and 2023 the portions of executive and non-executive incentive compensation that were excluded in the 2010 Rate Case Order, and the suggestion that any additional reduction should be made is unsupported and should be rejected. Furthermore, the small employee project management incentive program questioned by OPC witness Smith should remain in forecasted expense, as no Company capital is deployed in such construction projects, which are performed by large commercial customers on their facilities using their own capital. Therefore, OPC witness Smith's recommended adjustments should be rejected.

As previously demonstrated in my direct testimony, FPL's compensation and benefits expense is reasonable and prudent, and this fact has not been refuted by any witness in this case. Furthermore, FPL's expense requests for 2022 and 2023 do not include any type of expense that the Commission has not previously approved for recovery.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Liz Fuentes was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF LIZ FUENTES

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Liz Fuentes. My business address is Florida Power & Light Company ("FPL" or the "Company"), 9250 West Flagler Street, Miami, Florida 33174.

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

A. I am employed by FPL as Senior Director of Regulatory Accounting.

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

A. I am responsible for planning, guidance, and management of most regulatory accounting activities for FPL and Gulf Power Company ("Gulf"). In this role, I ensure that financial books and records comply with multi-jurisdictional regulatory accounting requirements and regulations.

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. That same year, I was employed by FPL. During my tenure at the Company, I have held various accounting and regulatory positions of increasing responsibility with most of my career focused in regulatory accounting and the calculation of revenue requirements. Specifically, I have filed testimony or provided accounting support in multiple FPL retail base rate filings, clause filings and other regulatory dockets filed at the Florida Public Service Commission ("FPSC" or the "Commission") as well as the Federal Energy Regulatory Commission ("FERC"). My responsibilities have included the management of the accounting for FPL's cost recovery clauses and the preparation, review and filing of FPL's monthly Earnings Surveillance Reports ("ESR") at the FPSC. I am a Certified Public Accountant ("CPA") licensed in the Commonwealth of Virginia and member of the American Institute of CPAs.

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

A. Yes. I am sponsoring the following exhibits:

- LF-1 Consolidated MFRs Sponsored or Co-sponsored by Liz Fuentes
- LF-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-sponsored by Liz Fuentes
- LF-3 MFR A-1 with RSAM for the 2022 Test Year and 2023 Subsequent Year
- LF-4 List of Proposed Company Adjustments for the 2022 Test Year and 2023 Subsequent Year
- LF-5 2022 and 2023 ROE Calculation Without Rate Adjustment
- LF-6 MFR A-1 without RSAM for the 2022 Test Year and 2023 Subsequent Year
- LF-7 ADIT Proration Adjustment to Capital Structure for 2022 Test Year and 2023 Subsequent Year
- LF-8 Schedule A-1 for FPL as a Separate Ratemaking Entity for the 2022 Test Year and 2023 Subsequent Year
- LF-9 Schedule A-1 for Gulf as a Separate Ratemaking Entity for the 2022 Test Year and 2023 Subsequent Year

I am co-sponsoring the following exhibits:

- TCC-9 Rates for FPL and Gulf as Separate Ratemaking Entities, filed with the direct testimony of FPL witness Cohen.
- REB-12 Solar Base Rate Adjustment Mechanism, filed with the direct testimony of FPL witness Barrett.

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. Yes. Exhibit LF-1 lists the consolidated MFRs that I am sponsoring and co-sponsoring.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format?"

A. Yes. Exhibit LF-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. What time periods are presented in the referenced consolidated MFRs and FPL and Gulf standalone schedules?

A. The referenced consolidated MFRs and FPL and Gulf standalone schedules reflect information for the 2020 Historical Test Year, 2021 Prior Year, 2022 Test Year, and 2023 Subsequent Year.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. FPL and Gulf consummated a legal merger January 1, 2021, and by the end of this year, operations will be essentially consolidated. In discussing operations and time periods after January 1, 2022, most references in my testimony will be only to "FPL" because FPL is proposing unified rates for the consolidated company. Therefore, unless otherwise noted, my testimony addresses requests for the consolidated company with unified rates.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the calculation of the revenue requirements and appropriateness of certain ratemaking adjustments FPL proposes in this proceeding. My testimony supports accounting and ratemaking practices that affect the determination of the appropriate rate base, working capital, rate of return, capital structure, and net operating income. Specifically, this includes:

1. The calculation of the revenue requirement requested for the 2022 Test Year;
2. The calculation of the revenue requirement requested for the 2023 Subsequent Year Adjustment ("2023 SYA"); and
3. Adjustments that FPL proposes to rate base, net operating income, and capital structure in order to properly represent the 2022 Test Year and 2023 Subsequent Year results for ratemaking purposes.

In addition, I support the accounting treatment for the consummation payment associated with the retirement of Scherer Unit 4, the recovery of the Gulf COVID-19 regulatory asset, and the calculation of revenue requirements for FPL's proposed Solar Base Rate Adjustment ("SoBRA") mechanism.

Q. Please summarize your testimony.

A. I sponsor and co-sponsor many MFRs and provide the calculation of net operating income, working capital, rate base, capital structure, and revenue requirements for the 2022 Test Year, and 2023 Subsequent Year. Based on these supporting calculations, FPL's requested base rate increase for the 2022 Test Year and 2023 Subsequent Year is $1,108 million and $607 million, respectively.

I also sponsor and co-sponsor many of the schedules included in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format" and provide the calculation of net operating income, working capital, rate base and revenue requirements for the 2022 Test Year, and the 2023 Subsequent Year for FPL and Gulf as separate ratemaking entities in the event the Commission does not approve FPL's request to unify rates in this proceeding.

In addition, I will present the regulatory asset recovery related to the Company's agreement with JEA to retire Scherer Unit 4 and discuss the appropriate recovery period of Gulf's regulatory asset for incremental bad debt expense and safety costs attributable to the COVID-19 pandemic.

Finally, I describe the methodology for the revenue requirement and true-up calculations for the proposed SoBRA mechanism consistent with the methodology previously approved in the Stipulation and Settlement Agreement reached in FPL's base rate case approved by the Commission in Order No. PSC-16-0560-AS-EI, Docket Nos. 160021-EI, 160061-EI, 160062-EI, and 160088-EI ("2016 Settlement Agreement") and the SoBRA calculations approved in Commission Order Nos. PSC-2018-0028-FOF-EI, PSC-2018-0610-FOF-EI and PSC-2019-0484-FOF-EI.

II. 2022 TEST YEAR REVENUE REQUIREMENT

Q. What is the amount of FPL's requested base rate increase for the 2022 Test Year?

A. As shown on Page 1 of Exhibit LF-3, MFR A-1 with Reserve Surplus Amortization Mechanism ("RSAM") for the 2022 Test Year, the amount of FPL's requested base revenue increase for 2022 is $1,108 million. This amount reflects the RSAM-adjusted depreciation rates discussed by FPL witness Ferguson in his testimony, which is consistent with the four-year rate plan submitted by the Company and discussed by FPL witness Barrett.

Q. Which MFRs directly support the 2022 Test Year revenue increase calculation?

A. Page 1 of Exhibit LF-3 reflects the MFRs that directly support the overall 2022 Test Year jurisdictional revenue requirement increase of $1,108 million requested by FPL. Those MFRs include schedules that support jurisdictional adjusted rate base of $55,508 million, jurisdictional adjusted net operating income of $2,971 million and the calculation of the jurisdictional revenue expansion factor of 1.34153 used to derive the requested revenue increase. Additionally, page 1 of Exhibit LF-3 references MFR D-1a which supports jurisdictional adjusted capital structure and the overall rate of return ("ROR") of 6.84% and reflects FPL's requested return on equity ("ROE") of 11.50% (including a one-half percent ROE performance incentive) that is further discussed in the testimony of FPL witnesses Coyne, Barrett and Reed.

Q. Did FPL apply any proposed Company adjustments in its calculation of jurisdictional revenue requirements for the 2022 Test Year?

A. Yes. A listing of the proposed rate base and net operating income Company adjustments for the 2022 Test Year and their amounts is reflected on pages 1 and 2 of Exhibit LF-4.

Q. Are there any other items you would like to address in regard to the calculation of revenue requirements for the 2022 Test Year?

A. Yes. Consistent with Order No. PSC-16-0506-FOF-EI, issued in Docket No. 160154-EI on November 2, 2016, a small amount of base revenue requirements associated with the Indiantown generating facility are currently being recovered on an interim basis through FPL's Capacity Cost Recovery Clause ("CCRC") because they were not contemplated in FPL's last rate case proceeding. To align all base rate costs, expenses, and revenues, the base revenues recovered through the CCRC related to the Indiantown generating facility are then reclassified on FPL's books and records from CCRC revenues to base revenues.

Although the Indiantown generating facility was retired at the end of 2020, FPL has reflected the land and ongoing base related expenses in its revenue requirement calculation for the 2022 Test Year. Therefore, FPL requests Commission authorization to recover the Indiantown site revenue requirements through base rates and discontinue recovery of Indiantown base revenue requirements through the CCRC effective January 1, 2022. This treatment is consistent with the methodology previously used to move recovery of FPL's West County Energy Center Unit 3 base revenue requirements from the CCRC to base rates pursuant to FPL's 2016 Settlement Agreement. FPL witness Cohen addresses the bill impact of this request. If the Commission does not approve recovery of the Indiantown site revenue requirements through base rates starting in 2022, FPL would continue recovery of its operating expenses through the CCRC.

Q. What would be the resulting ROE for the 2022 Test Year absent the requested rate adjustment?

A. Page 1 of Exhibit LF-5 shows that absent the requested rate adjustment, FPL's 2022 Test Year jurisdictional adjusted ROE is projected to be 8.40%, which is well below the bottom end of the ROE range supported by FPL witnesses Coyne and Barrett, and FPL's current authorized ROE range.

Q. Did you calculate an alternative 2022 revenue requirement that reflects the depreciation rates resulting from FPL's 2021 Depreciation Study instead of the RSAM-adjusted depreciation rates?

A. Yes, if the Commission does not approve FPL's four-year rate plan as described by FPL witness Barrett, the applicable depreciation rates would be those reflected in FPL's 2021 Depreciation Study. As shown on page 1 of Exhibit LF-6, which is MFR A-1 without RSAM, the amount of FPL's alternative base revenue increase for the 2022 Test Year is $1,311 million.

Q. Please describe how FPL calculated the alternative base rate increase for the 2022 Test Year.

A. FPL's alternative revenue requirements are premised on essentially the same data that was used to calculate the revenue increase for the 2022 Test Year reflected on MFR A-1 with RSAM. FPL replaced the proposed depreciation Company adjustments using RSAM-adjusted depreciation rates, and related Investment Tax Credit ("ITC") and excess accumulated deferred income tax ("EADIT") amortization adjustments discussed later in my testimony with Company adjustments reflecting the impact of the depreciation rates resulting from the 2021 Depreciation Study presented by FPL witness Ferguson in his testimony. These modifications resulted in an increase to the revenue increase reflected on MFR A-1 with RSAM for the 2022 Test Year of approximately $203 million.

III. 2023 SUBSEQUENT YEAR REVENUE REQUIREMENT

Q. What is the amount of FPL's requested base rate increase for the 2023 Subsequent Year?

A. As shown on page 2 of Exhibit LF-3, MFR A-1 with RSAM for the 2023

Subsequent Year, the amount of FPL's requested base revenue increase for 2023 is $607 million. This amount reflects RSAM-adjusted depreciation rates, which is consistent with FPL's four-year rate plan.

Q. Which MFRs directly support the 2023 SYA calculation?

A. Page 2 of Exhibit LF-3 reflects the MFRs that directly support the 2023 SYA jurisdictional revenue requirement of $1,723 million. Those MFRs include schedules that support FPL's jurisdictional adjusted rate base of $59,605 million, jurisdictional adjusted net operating income of $2,847 million and the calculation of the jurisdictional revenue expansion factor of 1.34156 to arrive at the requested revenue increase. Additionally, page 2 of Exhibit LF-3 also references MFR D-1a which supports jurisdictional adjusted capital structure that reflects FPL's requested ROE of 11.50% and an overall ROR of 6.93%.

Q. Are all of the proposed Company adjustments for the 2022 Test Year also applicable to the 2023 Subsequent Year?

A. Yes. FPL applied the proposed Company adjustments for the 2022 Test Year to the 2023 Subsequent Year consistently and reflected the amount of those adjustments in the calculation of jurisdictional revenue requirements for the 2023 Subsequent Year. A listing of the proposed rate base and net operating income Company adjustments for the 2023 Subsequent Year and their amounts is reflected on pages 1 and 2 of Exhibit LF-4.

Q. What would be the impact on ROE for the 2023 Subsequent Year absent the requested rate adjustment?

A. Page 1 of Exhibit LF-5 shows that, absent both the 2022 Test Year and 2023

Subsequent Year requested base rate adjustment, the 2023 jurisdictional adjusted ROE is projected to be 7.03%. The exhibit also shows that, with FPL's requested base adjustment for 2022 but absent the requested rate adjustment for 2023, the 2023 jurisdictional adjusted ROE is projected to be 157 basis points, or 1.57%, below the requested ROE.

Q. Did you calculate an alternative 2023 Subsequent Year revenue requirement that reflects the depreciation rates resulting from FPL's 2021 Depreciation Study instead of the RSAM-adjusted depreciation rates?

A. Yes. As shown on page 2 of Exhibit LF-6, which is MFR A-1 without RSAM, the amount of FPL's alternative base revenue increase for the 2023 Test Year is $601 million.

Q. Did FPL calculate the alternative base rate increase for the 2023 Subsequent Year in the same manner as the alternative base rate increase for 2022?

A. Yes, with the exception that FPL used 2023 Subsequent Year data.

IV. ADJUSTMENTS TO 2022 TEST YEAR AND 2023 SUBSEQUENT YEAR

Q. Has FPL presented Commission adjustments to rate base and net operating income necessary to properly reflect the 2022 Test Year and 2023 Subsequent Year for ratemaking purposes?

A. Yes. As required under prior Commission orders, FPL has reflected

Commission rate base and net operating income adjustments in the calculation of the 2022 Test Year and 2023 Subsequent Year revenue requirement calculations. These adjustments are detailed in MFRs B-2 and C-3 for their respective periods and are the same Commission adjustments reflected in FPL's monthly ESR. Due to the timing of the ultimate disposition of FPL's petition for disposition of SolarNow in Order No. PSC-2020-0508-TRF-EI, issued on December 18, 2020, Docket No. 20200209-EI, FPL was unable to incorporate the required Commission adjustments to remove all SolarNow costs, expenses, and revenues from its calculation of revenue requirements. FPL will instead include that Commission adjustment for both 2022 and 2023, which is expected to be minimal, in a separate filing.

Q. Has FPL proposed any Company adjustments in its calculation of rate base and net operating income for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. FPL is proposing various Company adjustments to its rate base and net operating income calculations for both the 2022 Test Year and 2023 Subsequent Year. A listing of FPL's proposed Company adjustments, their impact on rate base and/or net operating income, and the FPL witness supporting each one is reflected on pages 1 and 2 of Exhibit LF-4.

Q. Have all of FPL's proposed Company adjustments reflected on pages 1 and 2 of Exhibit LF-4 been incorporated into the calculation of jurisdictional rate base and net operating income for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. As reflected on MFRs B-2 and C-3 for their respective periods, FPL has included all proposed Company adjustments reflected on pages 1 and 2 of Exhibit LF-4 in its calculation of jurisdictional rate base and net operating income, respectively.

Q. Are there any Company adjustments to rate base or net operating income you are sponsoring that you would like to discuss?

A. Yes. I would like to discuss the following proposed Company adjustments:

- <u>Storm Protection Plan ("SPP") Costs</u> – As addressed in FPL's and Gulf's SPP Stipulation and Settlement Agreement approved by the Commission in Order No. PSC-2020-0293-AS-EI, FPL and Gulf each agreed to address the recovery of future SPP Operations & Maintenance ("O&M") expenses in its next base rate proceeding. As such, FPL is requesting authority to move recovery of all O&M expenses associated with its SPP from base rates to the SPP Cost Recovery Clause ("SPPCRC") starting in 2022 in order to align recovery of O&M program costs with their related capital expenditures. In addition, FPL proposes to move all remaining SPP capital expenditures, and any related depreciation, not currently recoverable through SPPCRC (i.e., Gulf's Transmission Inspection Program) from base rates to the

SPPCRC effective January 1, 2022. Cost of removal and retirements associated with FPL's SPP programs for assets existing prior to 2021 are forecasted to be recovered through base rates. The SPP O&M expenses and capital expenditures forecast for 2022 and 2023 used for this Company adjustment are reflected in FPL witness Spoor's testimony.

- <u>Capital Recovery Schedule Income Tax Adjustments</u> – Under the Tax Cuts and Jobs Act of 2017 (the "TCJA"), FPL is required to follow the Internal Revenue Service ("IRS") normalization requirements for EADIT attributable to the book and tax differences related to depreciation of public utility property as protected and employ the Average Rate Assumption Method ("ARAM"). The ARAM ensures that the amortization occurs no sooner than would occur as the book and tax differences turnaround. Per Order No. PSC-2019-0225-FOF-EI, Docket No. 20180046-EI, FPL is employing the ARAM for the turnaround of all protected EADIT and reflecting the amortization via base revenue requirements regardless of whether they relate to base or clause assets. However, when a major depreciable asset is retired early, it is proper to align any remaining EADIT amortization associated with the retired asset with the recovery of any unrecovered investment remaining at the time of retirement.[1] Therefore, FPL proposes to amortize the remaining EADIT associated with the total unrecovered investment reflected in the capital recovery schedules proposed and

[1] Rev. Proc. 2020-39, 2020-36 IRB 546, 08/14/2020, IRC Sec(s). 168

discussed in detail by FPL witness Ferguson over the same ten-year recovery period. In addition, FPL also proposes to adjust deferred income tax expense to account for permanent timing differences resulting from the capital recovery schedule amortization.

- Depreciation Income Tax Adjustments – As discussed in the testimony of FPL witness Ferguson, FPL is proposing the use of RSAM-adjusted depreciation rates as part of a four-year rate plan. Therefore, since this proposal changes the calculation of book depreciation and impacts the calculation of ARAM, FPL proposes to adjust EADIT amortization similar to the capital recovery schedule EADIT adjustment above in order to properly align depreciation expense and the turnaround of EADIT. As reflected on Exhibit LF-4, the change results in a decrease of EADIT amortization in the 2022 Test Year and 2023 Subsequent Year. In addition, FPL also proposes to adjust deferred income tax expense to consider permanent timing differences resulting from changes in forecasted book depreciation expense.
- Depreciation ITC Adjustment – As discussed in the testimony of FPL witness Ferguson, the useful lives of batteries are extended under FPL's 2021 Depreciation Study, and the lives of solar units are extended under FPL's proposed RSAM depreciation parameters, both of which are incorporated into FPL's proposed RSAM-adjusted depreciation rates. Therefore, in order to properly align ITC amortization with the recovery of these assets and maintain compliance with IRS normalization

requirements,[2] FPL proposes to decrease ITC amortization for the 2022 Test Year and 2023 Subsequent Year as reflected on Exhibit LF-4.

- Rate Case Expense Amortization – Consistent with FPL's 2016 Settlement Agreement and 2012 Settlement Agreement approved in Order No. PSC-13-0023-S-EI, FPL is requesting a four-year amortization period for estimated, incremental rate case expenses associated with this case totaling $5 million. In addition, FPL is requesting that the unamortized balance be included in rate base in the 2022 Test Year and 2023 Subsequent Year in order to avoid an implicit disallowance of reasonable and necessary costs. The fact that FPL is also requesting in one proceeding a 2023 SYA and a SoBRA Mechanism, which is discussed later in my testimony, reduces the amount of rate case expenses FPL would otherwise incur for multiple, back-to-back proceedings. Full recovery of necessary rate case expenses is appropriate but will not occur unless FPL is afforded the opportunity to earn a return on the unamortized balance of those expenses.

Q. Has FPL incorporated any adjustments other than Commission or Company adjustments in its calculation of revenue requirements for the 2022 Test Year or 2023 Subsequent Year?

A. Yes. As reflected on MFR D-1a for their respective periods, FPL has incorporated an adjustment to decrease the amount of Accumulated Deferred

[2] I.R.C. § 46(f) and Treas. Reg. § 1.46-6(g)

Income Tax ("ADIT") included in the calculation of FPL's weighted average cost of capital.

Q. Why has FPL made this adjustment to ADIT?

A. As required under Treasury Regulations §1.167(1)-1(h)(6), ADIT that is treated as zero cost capital or a component of rate base in determining a utility's cost of service must be calculated based on the same period as is used in determining the income tax expense utilized for ratemaking purposes. The Internal Revenue Code ("IRC") goes on to state that a utility may use either historical data or projected data in calculating these two amounts, but the periods used must be consistent. If the amounts are computed using projected data, in whole or in part, and the rates go into effect during the projected period, then the utility must use the formula provided in Treasury Regulations §1.167(1)-1(h)(6)(ii) to calculate the amount of ADIT to be included for ratemaking purposes. Because FPL is presenting a change in base rates at the beginning of both the projected 2022 Test Year and projected 2023 Subsequent Year, the Company is required to comply with Treasury Regulations §1.167(1)-1(h)(6) in this proceeding.

Q. Please describe the required formula FPL must follow to adjust ADIT in the 2022 Test Year and 2023 Subsequent Year.

A. Treasury Regulations §1.167(1)-1(h)(6)(ii) contain a precise formula ("Proration Requirement") for computing the amount of depreciation-related ADIT to be treated as zero cost capital when a future test period is used. The Proration Requirement is as follows:

> The pro rata portion of any increase to be credited or decrease to be charged during a future period…shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time such increase or decrease is to be accrued, and the denominator of which is the total number of days in the period.

Q. Did FPL include a Proration Requirement and adjustment to ADIT in its last rate case?

A. Yes. FPL calculated a Proration Requirement in its 2016 retail base rate filing and reflected an adjustment to ADIT on MFR D-1a in that docket. This treatment is also consistent with the Proration Requirement included in the calculation of the weighted average cost of capital applied to cost recovery clauses approved by the Commission in Order No. PSC-2020-0165-PAA-EU, Docket No. 20200118-EU.

Q. Please explain the calculation of the Proration Requirement and its impact to FPL's capital structure for the 2022 Test Year and 2023 Subsequent Year.

A. As reflected on page 1 of Exhibit LF-7, the calculations of the Proration Requirement for ADIT for the 2022 Test and 2023 Subsequent Year results begin with prorated average balances of $126 million and $107 million, respectively. FPL then compared the prorated average balances to the per-book 13-month average ADIT balances for 2022 and 2023 of $135 million and $115 million, respectively. The difference results in an adjustment to ADIT of $9 million for the 2022 Test Year and $8 million for the 2023 Subsequent Year, which are reflected as decreases to ADIT on MFR D-1a for their respective periods.

V. RETIREMENT OF SCHERER UNIT 4

Q. Please provide an overview of the retirement of Scherer Unit 4.

A. FPL and JEA jointly own Scherer Unit 4, an 850 MW coal-fired generating facility located in Georgia, with FPL owning 76.36% of the unit and JEA owning the remaining 23.64%. As discussed in the testimony of FPL witness Forrest, FPL and JEA have agreed to jointly retire Scherer Unit 4 on January 1, 2022. The early retirement and dismantlement of Scherer Unit 4 will result in unrecovered retired plant, which is addressed in the testimony of FPL witness Ferguson. As part of the agreement with JEA to retire Scherer Unit 4 discussed in FPL witness Forrest's testimony, FPL will make a Consummation Payment to JEA of $100 million to complete the retirement of the unit and unlock the value of the overall transaction for FPL's customers as described in the testimony of FPL witness Bores.

Q. How does FPL propose to record the unrecovered retired plant associated with the early retirement of Scherer 4?

A. As discussed by FPL witness Ferguson, FPL requests Commission authorization to establish a regulatory asset for the unrecovered retired plant at retirement as of January 1, 2022 of approximately $831 million and amortization on a straight-line basis over a 10-year period beginning in February 2022. This amount includes unrecovered retired plant associated with both base and clause recoverable assets. The regulatory asset will be recorded to FERC Account 182.2 – Unrecovered Plant and Regulatory Study Costs, and amortized to FERC Account 407 – Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs.

Q. How does FPL propose to record the Consummation Payment to JEA as part of the agreement to retire Scherer 4?

A. FPL requests Commission authorization to establish a regulatory asset for the Consummation Payment to JEA of $100 million, in recognition of FPL's proposal to defer and recover that specific cost in FPL's base rates. The payment will be recorded as a debit to a regulatory asset in FERC Account 182.3 – Other Regulatory Assets ("Scherer Consummation Payment"). FPL further requests to amortize the Consummation Payment on a straight-line basis to FERC Account 407.3 – Regulatory debit, over a ten-year period, beginning in February 2022. This amortization period is consistent with the recovery period for the unrecovered retired plant discussed in the testimony of FPL witness Ferguson.

Q. Has FPL reflected the recovery of the unrecovered retired plant and Scherer Consummation Payment regulatory assets in its 2022 Test Year and 2023 Subsequent Year revenue requirement calculations?

A. Yes. MFR C-3 for both the 2022 Test Year and 2023 Subsequent Year reflect the amortization of both the base portion of the unrecovered retired plant regulatory asset and Scherer Consummation Payment as Company adjustments to net operating income. In addition, FPL has reflected the unamortized balances of the base portion of the unrecovered retired plant regulatory asset and Scherer Consummation Payment in rate base for both the 2022 Test Year and 2023 Subsequent Year. Exhibit LF-4 lists the changes in rate base and amortization expense associated with these Company adjustments for the 2022 Test Year and 2023 Subsequent Year.

VI. COVID-19 REGULATORY ASSET

Q. Please discuss Gulf's request for approval to establish a regulatory asset for recording incremental costs attributable to COVID-19.

A. On May 22, 2020, Gulf requested approval to establish a regulatory asset for incremental bad debt expense and safety-related costs, less any savings, attributable to COVID-19 in Docket No. 20200151-EI. The concept of deferral accounting allows companies to defer incremental costs due to events beyond their control and seek recovery through rates at a later time. The incremental bad debt expense and safety-related costs Gulf incurred are attributable to the COVID-19 pandemic, a unique and extraordinary event beyond Gulf's control, that could not have been contemplated when Gulf's rates were last set.

Q. Did the Commission approve Gulf's request to establish a regulatory asset in Docket No. 20200151-EI?

A. Yes. The Commission approved Gulf's request in Order No. PSC-2020-0406-PAA-EI, issued October 27, 2020. However, the Office of Public Counsel ("OPC") protested the approval to establish the regulatory asset. FPL anticipates that a hearing will be scheduled in response to OPC's protest.

Q. What is the amount of the COVID-19 regulatory asset included for recovery in this proceeding?

A. The total COVID-19 regulatory asset requested for recovery in this proceeding is $21 million, which represents the sum of actual and forecasted incremental bad debt expense and safety-related costs, less savings, for the period April 1, 2020 through December 31, 2021. FPL has included the COVID-19 regulatory asset in rate base and is requesting amortization over a four-year period as a Company adjustment to the 2022 Test Year and 2023 Subsequent Year.

Q. How does FPL propose to incorporate the outcome of the COVID-19 docket in this proceeding?

A. FPL requests the Commission to incorporate its decision in the COVID-19 docket before the record is closed in this proceeding. If necessary, FPL will provide an adjustment to its revenue requirement calculations for 2022 and 2023 either in rebuttal testimony or promptly after the Commission renders a decision in the COVID-19 docket.

VII. 2024 AND 2025 SOLAR BASE RATE ADJUSTMENT MECHANISM

Q. How does FPL propose to calculate the revenue requirements under the SoBRA mechanism as described by FPL witness Valle?

A. Consistent with the methodology approved in FPL's 2016 Settlement Agreement and FPL's previous SoBRA filings approved in Commission Order Nos. PSC-2018-0028-FOF-EI, PSC-2018-0610-FOF-EI and PSC-2019-0484-FOF-EI, the SoBRA revenue requirement is intended to recover the incremental jurisdictional revenue requirement based on the first 12-months of solar facility operations beginning on the date the units are placed in-service. As provided and approved in the referenced SoBRA orders, the revenue requirement computations for the 2024 and 2025 SoBRAs will be based on the following: (1) estimated capital expenditures for each solar project, (2) estimated depreciation expense and related accumulated depreciation calculated using FPL's most recent approved depreciation rates for solar generation and transmission plant, and (3) estimated operating expenses. Additionally, each SoBRA will be calculated using FPL's approved midpoint ROE, an incremental capital structure that is adjusted to reflect the inclusion of investment tax credits on a normalized basis and the depreciation-related ADIT proration adjustment that is required by Treasury Regulation §1.167(1)-1(h)(6).

Q. Does FPL propose to submit its SoBRA revenue requirements to the Commission for approval before the units are expected to go into service?

A. Yes. Consistent with the process utilized by FPL for the SoBRAs approved by the Commission under FPL's 2016 Settlement Agreement, FPL will present its revenue requirement calculations at the time it makes its projection filings in the Fuel and Purchased Power Costs Recovery Clause Docket the year prior to the solar units' expected in-service date.

Q. Will there be a true-up to the initial SoBRA revenue requirement calculation in the event actual capital costs are lower than what was forecasted?

A. Yes. In the event that actual capital costs are lower than the forecasted capital costs reflected in the initial SoBRA, FPL will calculate a final SoBRA revenue requirement based on the same inputs and methodology used for the initial SoBRA revenue requirement, except the calculation will be updated with actual capital expenditures. This treatment is consistent with FPL's 2016 Settlement Agreement and the 2017 and 2018 SoBRA true-up filings approved in Commission Order Nos. PSC-2019-0484-FOF-EI and PSC-2020-0439-FOF-EI. In the event that actual capital costs for the 2024 and 2025 solar generation projects are higher than the projection on which the revenue requirements are based or the cost cap, FPL would include the incremental costs in its monthly earnings surveillance report and reflect these costs in its next base rate proceeding.

VIII. REVENUE REQUIREMENTS FOR FPL AND GULF AS SEPARATE RATEMAKING ENTITIES

Q. In the event the Commission does not approve FPL's request to unify FPL and Gulf base rates, has FPL calculated a base rate increase for the 2022 Test Year and the 2023 Subsequent Year for FPL as a separate ratemaking entity?

A. Yes. As reflected on Exhibit LF-8, which is Schedule A-1 for FPL as a separate ratemaking entity, the 2022 and 2023 base revenue increases for FPL are projected to be $1,155 million and $529 million, respectively. Additionally, page 2 of Exhibit LF-5 shows that, absent a rate adjustment, the 2022 Test Year and 2023 Subsequent Year jurisdictional adjusted ROE for FPL as a separate ratemaking entity is projected to be 7.98% and 9.99%, respectively. And, absent a rate adjustment in both 2022 and 2023, the adjusted ROE for FPL as a separate ratemaking entity is projected to be 6.67%.

Q. Has FPL applied all appropriate Commission adjustments, proposed Company adjustments, and the Proration Requirement to calculate the 2022 Test Year and 2023 Subsequent Year revenue requirements for FPL as a separate ratemaking entity?

A. Yes. As reflected on Schedules B-2, C-3, and D-1a for the 2022 Test Year and 2023 Subsequent Year provided in "Supplement 1 – FPL Standalone Information in MFR Format," FPL has applied all required Commission adjustments and the proration adjustment, and proposed Company adjustments applicable to standalone FPL for the 2022 Test Year and 2023 Subsequent Year. Pages 5 and 6 of Exhibit LF-4 lists all Company adjustments applicable to FPL as a separate ratemaking entity, their impact on rate base and/or net operating income for the 2022 Test Year and 2023 Subsequent Year, and the witness sponsoring each one. Page 2 of Exhibit LF-7 details the proration calculation for FPL as a separate ratemaking entity for the 2022 Test Year and 2023 Subsequent Year.

Q. Have similar base rate increase calculations been performed for Gulf as a separate ratemaking entity for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. As reflected on Exhibit LF-9, which is Schedule A-1 for Gulf as a separate ratemaking entity, the 2022 and 2023 base revenue increases for Gulf are projected to be $177 million and $78 million, respectively. Additionally, page 2 of$ Exhibit LF-5 shows that, absent a rate adjustment, the 2022 Test Year and 2023 Subsequent Year jurisdictional adjusted ROE for Gulf as a separate ratemaking entity is projected to be 5.33% and 9.14%, respectively. Absent a rate adjustment in both 2022 and 2023, the adjusted ROE for Gulf as a separate ratemaking entity is projected to be 3.79%.

Q. Did you also apply all appropriate Commission adjustments, proposed Company adjustments, and the Proration Requirement for Gulf as a separate ratemaking entity for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. As reflected on Schedules B-2, C-3, and D-1a for the 2022 Test Year and

2023 Subsequent Year provided in "Supplement 2 – Gulf Standalone Information in MFR Format," Gulf has separately applied all required Commission adjustments and the proration adjustment, and proposed similar Company adjustments for the 2022 Test Year and 2023 Subsequent Year. Pages 7 and 8 of Exhibit LF-4 list Company adjustments applicable to Gulf as a separate ratemaking entity, their impact on rate base and/or net operating income for the 2022 Test Year and 2023 Subsequent Year, and the witness sponsoring each one. Page 3 of Exhibit LF-7 details the proration calculation for Gulf as a separate ratemaking entity for the 2022 Test Year and 2023 Subsequent Year.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Liz Fuentes was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF LIZ FUENTES

DOCKET NO. 20210015-EI

JULY 14, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Liz Fuentes. My business address is Florida Power & Light Company ("FPL" or the "Company"), 9250 West Flagler Street, Miami, Florida 33174.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

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

A. Yes. I am co-sponsoring the following exhibits:

- LF-10 – FPL's Notice of Identified Adjustments filed May 7, 2021 and Witness Sponsorship
- LF-11 – FPL's Second Notice of Identified Adjustments filed May 21, 2021 and Witness Sponsorship

I am sponsoring the following exhibits:

- LF-12 – 2022 Test Year and 2023 Subsequent Year Recalculated Revenue Requirements with RSAM
- LF-13 – 2022 Test Year and 2023 Subsequent Year Recalculated Revenue Requirements without RSAM
- LF-14 – 2022 Test Year and 2023 Subsequent Year Recalculated Revenue Requirements for FPL as a Separate Ratemaking Entity
- LF-15 – 2022 Test Year and 2023 Subsequent Year Recalculated Revenue Requirements for Gulf Power as a Separate Ratemaking Entity

Q. How will you refer to FPL and Gulf Power when discussing them in your rebuttal testimony?

A. Similar to my direct testimony, most references in my testimony will be only to "FPL" because FPL is proposing unified rates for the consolidated company (i.e., FPL and Gulf Power as one ratemaking entity). Therefore, unless otherwise noted, my rebuttal testimony addresses base revenue requests for the consolidated Company with unified rates.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to certain assertions and recommendations in the testimony of Office of Public Counsel ("OPC") witness Smith and Florida Industrial Power Users Group ("FIPUG") witness LaConte. The issues I address in rebuttal to these witnesses are rate case expenses and Construction Work In Progress ("CWIP"). In addition, I present FPL's recalculated base revenue increases for the 2022 Test Year and 2023 Subsequent Year to incorporate FPL's previously identified adjustments and the removal of the COVID-19 regulatory asset and related amortization as a result of the recent Florida Public Service Commission ("FPSC" or the "Commission") approval of a settlement on this matter.

Q. Please summarize your rebuttal testimony.

A. Consistent with Commission rules and practice, unamortized rate case expenses and CWIP balances not accruing Allowance for Funds Used During Construction ("AFUDC") should be included in the calculation of FPL's rate base as reflected in its Minimum Filing Requirements ("MFRs"). In addition, the forecasted amount of FPL's rate case expenses of $5 million included in my direct testimony is the proper amount to include for recovery in this proceeding.

I calculated the revenue requirement impacts to the 2022 Test Year and 2023 Subsequent Year resulting from FPL's previously filed identified adjustments to rate base, net operating income ("NOI"), capital structure, and the NOI multiplier, and the removal of the COVID-19 regulatory asset and related amortization. Based on these adjustments, FPL's recalculated base revenue increases for the 2022 Test Year and 2023 Subsequent Year are $1,075 million and $605 million, respectively. The recalculated base revenue increases for 2022 and 2023 are lower than the amounts reflected in my direct testimony and on MFR A-1 with Reserve Surplus Amortization Mechanism ("RSAM") by approximately $34 million and $1 million, respectively.

II. RATE CASE EXPENSES

Q. FPL includes the recovery of forecasted rate case expenses in its revenue requirements for 2022 and 2023. Please explain why this is appropriate.

A. It is proper to include a forecasted level of rate case expense in FPL's calculation of revenue requirements for 2022 and 2023 for two reasons. First, all components of FPL's revenue requirement calculation – not just rate case expenses – are based on forecasted test years. Isolating one component of the calculation to reflect actual costs is inappropriate. Second, although FPL expects rate case expenses to remain at its originally forecasted amount of $5 million, actual incremental rate case expenses are not expected to be finalized until the fourth quarter of this year. There is no readily available avenue to address or review the final costs before the Commission makes its decision in this proceeding, therefore rendering impracticable FIPUG witness LaConte's recommendation to include only actual expenses.

Q. Should the Commission allow FPL to include unamortized rate case expenses in rate base?

A. Yes. As stated in my direct testimony, the inclusion of unamortized rate case expenses in rate base is consistent with the treatment approved in FPL's last two base rate orders. I am aware that the FPSC decided against inclusion of unamortized rate case expenses in rate base in the orders quoted by OPC witness Smith. However, such recommended treatment results in an implicit disallowance of otherwise prudently incurred incremental costs required by the Company to litigate its case and present evidence effectively. This practice imposes an unwarranted penalty on the Company for seeking rates that will allow it an opportunity to recover its costs to provide service, invest for the benefit of customers, and earn a reasonable return on its investments. Therefore, FPL should be allowed to include unamortized rate case expenses in its rate base, and OPC witness Smith's and FIPUG witness LaConte's arguments to the contrary should be rejected.

Q. Did FPL reflect the proper amount of unamortized rate case expenses in rate base in its original filing?

A. Yes. As reflected on page 8 of MFR B-6 for the 2022 Test Year, FPL included $5 million of forecasted deferred rate case expenses in rate base in its base forecast. FPL then layered on a Company adjustment to reduce rate base to reflect amortization of this balance over four years for $646 thousand (13-month average) in 2022, which is reflected on page 3 of MFR B-2. As such, FPL reflected the proper amount of unamortized rate case expenses of $4.5 million in 2022 in its original filing and did not require a rate base adjustment to correct its proposed amortization of deferred rate case expenses as asserted by OPC witness Smith in his testimony. In addition, FPL followed the same process for the 2023 Subsequent Year and likewise, did not require a base rate adjustment to correct the amount of unamortized rate case expense in its filing. OPC witness Smith's assertion that FPL required a correction is unfounded and unsupported.

III. CWIP IN RATE BASE

Q. Can you please explain the Commission's current policy as it relates to earning a return on CWIP balances?

A. Yes. Rule 25-6.0141, Florida Administrative Code, (the "AFUDC Rule"), recognizes that a return on CWIP balances can be achieved in either of two ways. First, CWIP projects that meet the requirements set forth in section (2)(a) of the AFUDC Rule may accrue AFUDC and are removed from rate base. Second, CWIP projects that do not meet the requirements to accrue AFUDC are included in rate base (i.e., non-interest bearing CWIP).

Q. Aside from the language of the AFUDC Rule, do you believe non-interest bearing CWIP should be included in rate base?

A. Yes. Although CWIP represents assets under construction that are not yet in-service, FPL has deployed incremental debt and equity in order to construct these new assets to continue to provide quality and cost effective service to its customers. OPC witness Smith's assertion that CWIP is not used and useful and should not be included in rate base ignores that the construction phase is a necessary part of providing electric service.

Q. When was the AFUDC Rule last amended by the Commission?

A. The Commission last amended the AFUDC Rule in January 2021 after issuing a notice of proposed rulemaking on the AFUDC Rule in June 2020 and discussing proposed revisions with interested parties and reviewing their comments. FPL and other interested parties, including OPC, participated in various rulemaking workshops and filed comments on proposed rule revisions during this rulemaking process.

Q. Did OPC take a position regarding the AFUDC Rule during that process?

A. Yes. OPC commented that utilities must not include AFUDC on CWIP projects that were included in rate base when a utility last set its base rates in order to avoid double recovery. This demonstrates that OPC did not dispute the inclusion of non-interest bearing CWIP in rate base, which is inconsistent with OPC witness Smith's opinion that it should be removed from rate base.

IV. REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED BY FPL

Q. Has FPL identified adjustments that should be made to the revenue requirement calculations for the 2022 Test Year and 2023 Subsequent Year?

A. Yes. The identified adjustments to the calculation of revenue requirements for the 2022 Test Year and 2023 Subsequent Year are reflected in the two notices of identified adjustments previously filed by FPL during the course of this proceeding, which are included in Exhibits LF-10 and LF-11. In addition, FPL has one additional adjustment to remove the $21 million COVID-19 regulatory asset and its related amortization from FPL's revenue requirement calculations.

Q. Please explain why FPL is removing the COVID-19 regulatory asset and related amortization from revenue requirements in this proceeding.

A. On June 15, 2021, Gulf Power and OPC filed a joint motion for the approval of a Stipulation and Settlement Agreement (the "COVID-19 Settlement") that would resolve all issues in Docket No. 20200151-EI, Petition for Approval of Regulatory Asset To Record Costs Incurred Due to COVID-19. The COVID-19 Settlement allows Gulf Power to establish a regulatory asset not to exceed $13.2 million as of June 30, 2021 with recovery through the Capacity Cost Recovery Clause over a three-year period beginning January 1, 2022. Since the

COVID-19 Settlement was approved by the Commission on July 8, 2021, FPL has removed these costs from its base rate request in this proceeding.

Q. How does FPL propose that the Commission use the adjustments reflected on Exhibits LF-10 and LF-11 in this proceeding?

A. The Commission should include the effect of the adjustments in determining FPL's revenue requirements for the 2022 and 2023 requested base revenue increases. Some of those adjustments will result in increases to revenue requirements while others will result in decreases, but the net impact of the adjustments is a reduction in FPL's revenue requirements for each of those years.

Q. What is the amount of FPL's recalculated base revenue increase for the 2022 Test Year and 2023 Subsequent Year?

A. As shown on Page 1 of Exhibit LF-12, the amounts of FPL's recalculated base revenue increases for 2022 and 2023 are $1,075 million and $605 million, respectively. The recalculated amounts are based on MFR A-1 with RSAM, which is consistent with FPL's four-year rate plan discussed by FPL witness Barrett, and include all applicable identified adjustments reflected on Exhibits LF-10 and LF-11 and the removal of the COVID-19 regulatory asset and related amortization. Pages 2 through 6 of Exhibit LF-12 present the impact of each adjustment to rate base, NOI, capital structure, and the NOI multiplier. The recalculated base revenue increases for 2022 and 2023 are lower than the amounts reflected on MFR A-1 with RSAM by approximately $34 million and $1 million, respectively.

Q. Did FPL recalculate the alternative base revenue increases that would be required for the 2022 Test Year and 2023 Subsequent Year in the event the Commission does not approve FPL's proposed four-year rate plan?

A. Yes. As shown on Page 1 of Exhibit LF-13, the amount of FPL's recalculated alternative base revenue increase for 2022 and 2023 is $1,277 million and $600 million, respectively. The recalculated amounts are based on MFR A-1 without RSAM, and include all applicable identified adjustments reflected on Exhibits LF-10 and LF-11 and the removal of the COVID-19 regulatory asset and related amortization. Pages 2 through 6 of Exhibit LF-13 present the impact of each adjustment to rate base, NOI, capital structure, and the NOI multiplier. The recalculated base revenue increases for 2022 and 2023 are lower than the amounts reflected on MFR A-1 without RSAM by approximately $34 million and $1 million, respectively.

Q. How do FPL's recalculated revenue requirements under FPL's proposed four-year plan compare to the recalculated revenue requirements that would apply if the Commission does not approve the four-year plan?

A. FPL's recalculated revenue requirements under the four-year plan remain about $200 million lower per year compared to the alternative revenue requirements. Over four years, this amounts to roughly $800 million of lower revenue requirements, which does not account for any additional base revenue increases in 2024 and 2025 that would result if the four-year plan is not approved, as discussed by FPL witnesses Barrett and Bores.

Q. Has FPL recalculated the base revenue increases for the 2022 Test Year and 2023 Subsequent Year that would apply to FPL as a separate ratemaking entity in the event the Commission does not approve FPL's request to unify FPL and Gulf Power base rates?

A. Yes. As shown on Page 1 of Exhibit LF-14, the amount of FPL's recalculated base revenue increase for 2022 and 2023 as a separate ratemaking entity is $1,135 million and $530 million, respectively. The recalculated amounts are based on Schedule A-1 for FPL as a separate ratemaking entity, and include all applicable identified adjustments reflected on Exhibits LF-10 and LF-11. Pages 2 through 6 of Exhibit LF-14 present the impact of each adjustment to rate base, NOI, capital structure, and the NOI multiplier. The recalculated base revenue increase for 2022 is approximately $20 million lower than the amount reflected on Schedule A-1 for FPL as a separate ratemaking entity while the amount for 2023 is approximately $1 million higher.

Q. Has a similar calculation been performed for Gulf Power as a separate ratemaking entity?

A. Yes. As shown on Page 1 of Exhibit LF-15, the amount of Gulf Power's recalculated base revenue increase for 2022 and 2023 as a separate ratemaking entity is $163 million and $81 million, respectively. The recalculated amounts are based on Schedule A-1 for Gulf Power as a separate ratemaking entity, and include all applicable identified adjustments reflected on Exhibits LF-10 and LF-11 and the removal of the COVID-19 regulatory asset and related amortization. Pages 2 through 6 of Exhibit LF-15 present the impact of each adjustment to rate base, NOI, capital structure, and the NOI multiplier. The recalculated base revenue increase for 2022 is approximately $14 million lower than the amount reflected on Schedule A-1 for Gulf Power as a separate ratemaking entity while the amount for 2023 is approximately $3 million higher.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Whereupon, prefiled direct testimony of Tara B. DuBose was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF TARA B. DUBOSE

DOCKET NO. 20210015-EI

MARCH 12, 2021

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tara B. DuBose. 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 the Manager of Cost of Service and Load Research in the Rates & Tariffs Department.

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

A. I am responsible for managing FPL's and Gulf's load research and cost of service activities for retail rates. In this capacity, my responsibilities include the preparation and filing of the load research sampling plans and study results with the Florida Public Service Commission ("FPSC" or the "Commission"), the development of annual energy and demand line loss factors by rate class, and the preparation of jurisdictional separation and retail cost of service studies.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Business Administration with a concentration in Accounting from the University of South Carolina - Aiken in 1996. In 2007, I earned a Master of Business Administration with a concentration in International Business from the University of South Carolina. I am also a Certified Public Accountant in the state of South Carolina. From 1996 to 2000, I was employed as a Financial Analyst for the Comptroller

General's office for the state of South Carolina and as an Auditor in public accounting firms. From 2000 to 2011, I was employed at SCANA Corporation (now Dominion Energy), where I held a variety of positions including Auditor III in Internal Audit, Senior Regulatory Accountant for Retail Electric and Gas Distribution Rates, and Supervisor of Electric Transmission Rates and Gas Transportation Rates. I joined FPL in 2011 as a Principal Rate Analyst for Rate Design, responsible for retail tariff and rate development and progressed to my current position of Manager of Cost of Service and Load Research.

I am a member of the Edison Electric Institute ("EEI") Rates and Regulatory Affairs Committee. I have completed various relevant training courses throughout my career including the New Mexico State University Center for Public Utilities Basics Course, the EEI Advanced Rate Design Course, the EEI and University of Wisconsin - Madison Transmission & Wholesale Markets School and the Association of Edison Illuminating Companies ("AEIC") Fundamentals of Customer Load Data Analysis Course. I have also served as the Chairman of the Southeastern Electric Exchange ("SEE") Rate & Regulatory Committee and have been a guest speaker at SEE Committee meetings.

Q. Have you previously testified before this Commission?

A. No. I have filed testimony before the Federal Energy Regulatory Commission ("FERC") in wholesale rate and cost of service matters.

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

A. Yes. I am sponsoring the following exhibits:

- TBD-1 Consolidated MFRs Sponsored or Co-Sponsored by Tara B. DuBose
- TBD-2 Supplemental FPL and Gulf Standalone Information in MFR Format Sponsored or Co-Sponsored by Tara B. DuBose
- TBD-3 Load Research Rate Classes and Related Rate Schedules
- TBD-4 Rate Class Extrapolation Methodologies
- TBD-5 Rates of Return and Parity at Present Rates
- TBD-6 Target Revenue Requirements at Proposed Rates
- TBD-7 Informational Consolidated MDS Cost of Service in MFR Format
- TBD- 8 Comparison of Proposed Target Revenue Requirements by Rate Class with and without MDS

I am co-sponsoring the following exhibit:

- TCC-9- Rates for FPL and Gulf as Separate Ratemaking Entities, filed with the direct testimony of FPL witness Cohen.

Q. Are you sponsoring or co-sponsoring any consolidated Minimum Filing Requirements ("MFRs") in this case?

A. Yes. Exhibit TBD-1 lists the consolidated MFRs that I am sponsoring or co-sponsoring.

Q. Are you sponsoring or co-sponsoring any schedules in "Supplement 1 – FPL Standalone Information in MFR Format" and "Supplement 2 – Gulf Standalone Information in MFR Format"?

A. Yes. Exhibit TBD-2 lists the supplemental FPL and Gulf standalone information in MFR format that I am sponsoring and co-sponsoring.

Q. How will you refer to FPL and Gulf when discussing them in testimony?

A. Gulf was acquired by FPL's parent company, NextEra Energy, Inc., on January 1, 2019. On January 1, 2021, FPL and Gulf were legally merged but maintained their status as separate ratemaking entities. In this proceeding, FPL is seeking to consolidate the FPL and Gulf rates into a single FPL rate-regulated entity effective January 1, 2022.

For purposes of my testimony, operations or time periods prior to January 1, 2019 (when Gulf Power Company was acquired by FPL's parent company, NextEra Energy, Inc.), "FPL" and "Gulf" will refer to their pre-acquisition status, when they were legally and operationally separate companies. For operations or time periods between January 1, 2019, and January 1, 2022, "FPL" and "Gulf" will refer to their status as separate ratemaking entities, recognizing that they were merged legally on January 1, 2021, and consolidation proceeded throughout this period. Finally, operations or time periods after January 1, 2022, are referred to as "FPL" only because Gulf will be consolidated into FPL. Therefore, unless otherwise noted, my testimony addresses requests for the consolidated Company.

Q. What is the purpose of your testimony?

A. First, my testimony explains what load research is, how it is used in jurisdictional separation and cost of service studies, and how the projected load forecasts by rate class were developed. Second, I explain the process used to develop the consolidated FPL jurisdictional separation studies including the line loss factors and resulting jurisdictional separation factors. Third, I explain the process of preparing a retail cost of service study and explain the proposed methodologies to allocate production, transmission, and distribution plant to retail rate classes. Lastly, I discuss the results of the consolidated FPL retail cost of service studies for the 2022 Test Year and 2023 Subsequent Year, and briefly describe the standalone FPL and Gulf studies presented in supplemental schedules.

Q. Please summarize your testimony.

A. My testimony supports the results of the consolidated FPL cost of service studies for the projected 2022 Test Year and 2023 Subsequent Year. The proposed consolidated FPL cost of service study fairly presents each rate class's cost responsibility, rate of return ("ROR"), and parity position (*i.e.*, rate class ROR relative to system average ROR). The consolidated FPL load research study, which provides the basis for cost allocations, is developed from the historical FPL and Gulf load research sampling plans approved by this Commission. The separation studies are conducted to allocate rate base, revenues, and expenses between retail and wholesale jurisdictions. The retail cost of service studies allocate the retail jurisdictional rate base, revenues, and expenses to the individual rate classes based on the appropriate cost drivers previously approved by this Commission.

The results of the consolidated FPL rate class cost of service studies show that at present rates several rate classes, such as RS(T)-1, the small General Service classes and the Lighting classes, are well above parity, while some of the larger commercial/industrial rate classes, particularly GSLD(T)-1,GSLD(T)-2, and GSLD(T)-3, are well below parity. Exhibit TBD-5 lists the ROR and related parity index for each rate class along with the revenue requirement and percent differential needed to achieve full parity at present rates, before any revenue increase is applied. MFR E-1 provides the details supporting these results.

Finally, the consolidated FPL cost of service study provides target revenue requirements by rate class and the underlying unit costs for each billing determinant, *e.g.*, demand, energy, lighting, and customer charges. This information is presented on MFR E-6b and provides the basis for designing rates that would improve the parity among rate classes and better align the consolidated FPL rates and charges with the costs to serve each rate class. Exhibit TBD-6 shows the target revenue requirements for each rate class at proposed rates on an equalized basis, that is, at the retail ROR or at parity.

The Commission should approve the consolidated FPL jurisdictional separation and cost of service study methodologies and results presented in my testimony.

The methodologies used to allocate rate base, revenues, and expenses were accurately applied and are consistent with those previously approved by this Commission. The results of the cost of service study are fair, reasonable, and utilize cost allocation methodologies that ensure the continued delivery of exceptional value to customers by properly allocating costs to rate classes.

II. LOAD RESEARCH STUDIES

Q. What is a load research study, and why is it a necessary input into the jurisdictional separation and cost of service studies?

A. A load research study provides information on customer usage characteristics, which provides the basis for allocating costs between retail and wholesale jurisdictions and for allocating costs among retail rate classes. Rule 25-6.0437, Florida Administrative Code ("F.A.C."), Cost of Service Load Research, requires that investor-owned utilities serving more than 50,000 retail customers submit a load research sampling plan to the Commission for review and approval every three years. The rule also states that "the approved sampling plan shall be used for all load research performed for cost of service studies and other studies submitted to the Commission until a new sampling plan is approved by the Commission."[1]

[1] The Rule also requires that utilities submit a complete load research study every three years. FPL's most recent load research study was filed with the Commission in December 2020, and Gulf's most recent load research study was filed and approved by the Commission in August 2018.

Q. Has the Commission reviewed and approved the load research sampling plans used in this filing?

A. Yes. FPL's most recent sampling plan for sample deployments for the years 2020 to 2022 was approved in July 2020, and Gulf's most recent sampling plan for approval of sample deployments for the year 2021 was submitted in November 2020. However, because it was necessary to prepare the load research studies supporting this filing using 2019 data, the underlying studies are based on sampling plans previously approved in June 2017 for FPL and October 2017 for Gulf.

Q. What information is provided by load research?

A. For each wholesale customer and retail rate class ("rate class"), load research provides the class contribution to the system peak (Coincident Peak or "CP"), the class peak (Group Non-Coincident Peak or "GNCP"), the customers' Non-Coincident Peak ("NCP"), and the class energy consumption or kilowatt hours ("kWh"). The CP represents the rate class demand at the time of the system peak. The GNCP represents a rate class's maximum demand as a class, regardless of the time of the system peak. The NCP is the sum of the peak demands for all customers within the rate class, regardless of when they occur. The kWh is the aggregation or sum of the class usage for the year. Load research also provides load shapes, hourly data, and load factors for each rate class. Load research data reflecting these attributes is developed on a monthly basis for each wholesale customer and retail rate class. The monthly data is analyzed and reported on an annual basis as well.

Q. Please explain what is meant by "rate classes."

A. In general terms, rate classes are groups of individual rate schedules with like billing attributes (*e.g.*, customer type and load size) and rate design inter-relationships that are combined for rate design purposes. As a result, one or more rate schedules may be combined into a single rate class. The practice of combining rate schedules with similar load profiles is consistent with FPL's cost of service studies filed in the last six rate cases (Docket Nos. 830465-EI, 001148-EI, 050045-EI, 080677-EI, 120015-EI and 160021-EI).

Q. How is load research information developed by rate class?

A. The first step is to collect and analyze historic load data by rate class. For the majority of the rate classes, load data is captured by Advanced Metering Infrastructure ("AMI") meters used for billing purposes. The data from the AMI meters is validated and processed in the Oracle Utilities Load Analysis computer application. The interval load data is analyzed on a calendar month basis to derive the average load data and usage statistics.

Statistical samples developed in compliance with Rule 25-6.0437, F.A.C., are used for rate classes with large population sizes, while those with smaller population sizes are 100 percent studied (census classes) and do not require statistical sampling. Unmetered rate classes, such as certain street light classes, are modeled based on their equipment usage characteristics.

Following the collection and verification of data, one of the two extrapolation methodologies identified in Exhibit TBD-4 is used to estimate the load research data for each metered rate class: (1) Ratio Extrapolation or (2) Mean Per Unit Extrapolation. The Ratio Extrapolation methodology is used to expand the historical load research data for sampled rate classes and larger census rate classes. This methodology estimates the total rate class demand by applying the ratio of demand to billed energy for each interval recorded multiplied by the billed energy for the rate class. The Mean Per Unit Extrapolation methodology is used for smaller census rate classes. This methodology estimates the total rate class demand by multiplying the number of customers in the rate class by the average demand for each interval recorded. Both extrapolation methodologies are used for metered rate classes, as necessary, to account for missing interval data resulting from meter, data translation, or communication issues.

Non-metered lighting rate classes, such as SL-1 and OL-1 for former FPL and OS I, II and III for former Gulf, are modeled based on the estimated number of burn hours or estimated hours of operation. This modeling estimates that light fixtures are in use approximately 49% of all hours in a year. The Traffic Signal Service rate class, SL-2, is modeled based on constant usage or a 100% load factor.

The load research sampling and extrapolation methodologies described above are in accordance with the Association of Edison Illuminating Companies Load Research & Analysis Manual and are standard practices widely used in the utility industry. These methodologies have been applied on a consistent basis in load research filings with the Commission for FPL.

Q. How are the rate classes determined for the consolidated FPL load research study?

A. The rate classes for the consolidated FPL load research study are the FPL rate classes with former Gulf customers included. The mapping of Gulf customers to FPL rate classes is discussed by FPL witness Cohen. Customer migration for Gulf customers was based on their available billing data for 2019, which determined the best fit consolidated FPL rate class for former Gulf customers. For former Gulf customers in sampled rate classes, migration sub-group load profiles are developed. The sub-group profiles are then combined with FPL rate class profiles using ratio analysis weighted by energy (kWh). For census classes, where 100 percent of the rate class population is included in the study, individual customers are migrated to FPL rate classes by incorporating their usage characteristics into the target FPL rate class analysis. For the unmetered former Gulf lighting rate classes, with a few exceptions, customers are migrated to street lighting or traffic signal classes by incorporating the number, type, and modeled energy usage into target FPL modeled rate class analysis.

Q. Have you prepared an exhibit that lists the rate classes used for load research purposes?

A. Yes. Exhibit TBD-3 lists and describes the rate classes used for load research study purposes. Exhibit TBD-3 also lists the rate classes that are sampled, census, or modeled for load research purposes.

Q. How is the load research data developed for the consolidated FPL load research study?

A. To prepare the consolidated FPL load research study, it is necessary to first develop FPL and Gulf load research studies based on the prior FPL and Gulf load research sampling plans approved by the Commission in compliance with the Commission's precision requirements.[2] The Gulf load research study results developed for this filing are consistent with the results of the Gulf load research study filed in 2019, based on Gulf methodologies and processes. In instances where the prior FPL and Gulf load research studies differ in methodologies or processes, FPL methodologies and processes are used to better align the two studies for the proposed consolidated FPL study.

For FPL, the monthly load research data for the most recently completed three-year annual load research studies is used to project the peak loads by rate class.

[2] Rule 25-6.0437(3), F.A.C., provides that the sampling plan shall be designed to provide the following levels of precision: (i) estimates of the averages of the 12 monthly coincident peaks for each class within plus or minus 10 percent at the 90 percent confidence level; (ii) estimates of the summer and winter peak demands for each rate class within plus or minus 10 percent at the 90 percent confidence level, except for the General Service Non-Demand rate class; and (iii) estimates of the summer and winter peak demands for the General Service Non-Demand rate class within plus or minus 15 percent at the 90 percent confidence level.

The FPL load research data for the historical years 2017, 2018, and 2019 are provided in Supplement 1, MFR E-11, Attachments 2, 3, and 4, respectively.

For Gulf, monthly load research data for the most recently completed annual load research study is used to project the peak loads by rate class. The Gulf load research data for the historical year 2019 is provided in Supplement 2, MFR E-11, Attachment 2. One year is used for Gulf due to how often Gulf conducted load research analysis compared to FPL.

For consolidated FPL, the 2019 monthly load research data for FPL was combined with one year of historic monthly load research data for Gulf to project the peak loads by rate class. The consolidated FPL load research data is provided in MFR E-11, Attachment 2.

Q. Please summarize the results achieved in the historical load research studies supporting this filing.

A. As previously mentioned, individual load research studies have been prepared for FPL, Gulf, and consolidated FPL. The studies provide the estimated CP and GNCP and NCP demands for the 12-month period ending December 31, 2019, for all rate classes subject to reporting under Rule 25-6.0437, F.A.C. Also included in the reports for the historic FPL and Gulf sampled rate classes are the 90% confidence intervals around the monthly peak demands and their percent relative accuracy. The FPL and Gulf studies meet the target level of statistical accuracy required by the Rule for the estimate of averages of the 12 monthly CP, as well as for the summer and winter peaks of the sampled rate classes.

Q. Please describe how the forecasted 2022 Test Year and 2023 Subsequent Year load research data were developed.

A. The historical load research information described previously provides the basis for the forecasted 2022 Test Year and 2023 Subsequent Year load data shown in MFR E-11, Attachment 1 for consolidated FPL and in Supplements 1 and 2, MFR E-11, Attachment 1 for standalone FPL and standalone Gulf, respectively. First, monthly ratios of each rate class's historical CP, GNCP, and NCP to actual kWh sales are developed for each year of actual load research data. These ratios are then applied to the sales forecast by rate class to derive the forecasted CP, GNCP, and NCP demands for each class. For the 2022 Test Year and 2023 Subsequent Year, the sales forecast by rate class is provided by FPL witness Cohen based on the load forecast by revenue class developed by FPL witness Park.

Q. Has this method of developing forecasted load research information been previously used in Commission proceedings?

A. Yes. The methodology for applying historical data to forecast rate class load is the same methodology used in prior Commission rate cases and cost recovery clause filings. The forecasted load research data in FPL's MFR filings in Commission Docket Nos. 001148-EI, 050045-EI, 080677-EI, 120015-EI and 160021-EI utilized this same methodology.

Q. Is the forecasted load research data by rate class consistent with the system load forecast?

A. Yes. The forecasted load research data is consistent with the forecast of system monthly peak demands for the 2022 Test Year and 2023 Subsequent Year presented in MFR E-18, and with the forecast of system sales for the 2022 Test Year and 2023 Subsequent Year presented in MFR F-8 for consolidated FPL. For standalone FPL and standalone Gulf, this same information is presented in Supplements 1 and 2, MFR E-18 and MFR F-8, respectively.

Q. Which MFRs provide additional information on load research?

A. MFR E-9 and MFR E-17 provide additional information on load research for consolidated FPL. Supplements 1 and 2, MFR E-9 and MFR E-17 provide the same information for standalone FPL and standalone Gulf, respectively.

III. JURISDICTIONAL SEPARATION STUDY

Q. What is a jurisdictional separation study, and how is it used to develop the cost of service study?

A. A jurisdictional separation study allocates the Company's total rate base and net operating income ("NOI") between different rate-regulated jurisdictions. The consolidated FPL utility business operates under two rate-regulated jurisdictions: retail, regulated by this Commission; and wholesale, regulated by the FERC. FPL must maintain its accounting books and records in accordance with the Uniform System of Accounts as prescribed by the FERC and the

Commission. Compliance with the Uniform System of Accounts requires electric utilities to record costs incurred and investments made at original cost. Because most investments made and costs incurred by a regulated utility serve both retail and wholesale customers, it is necessary to prepare a jurisdictional separation study to allocate rate base and NOI items recorded on the Company's accounting books and records between the retail and wholesale jurisdictions. Costs that are allocated to the retail jurisdiction are then allocated to retail rate classes through the cost of service study.

Q. What are the steps in the jurisdictional separation study?

A. Costs are first functionalized, then classified, and finally allocated between the retail and wholesale jurisdictions. The term "functionalization" refers to the assignment of costs into one or more of the major functions of an electric utility (*e.g.*, production, transmission and distribution). The term "classification" refers to the categorization by cost driver – that is, the determination of whether a cost is driven by demand, energy, or number of customers. Finally, each component is "allocated" between jurisdictions using jurisdictional separation factors. The method of allocating a cost should be consistent with its functionalization and classification. For example, a cost classified as demand-related should not be allocated on the basis of kWh of energy consumed, nor should a cost classified as energy-related be allocated based on peak demand.

Q. What are jurisdictional separation factors?

A. Jurisdictional separation factors are the result of the process just described and are used to allocate rate base and NOI items between retail and wholesale jurisdictions. A factor of zero indicates no retail responsibility, and a factor of one indicates 100% retail responsibility. The jurisdictional separation factors are primarily based on demand or energy sales for the retail and wholesale jurisdictions. However, other factors that best represent each jurisdiction's cost responsibility are also used. MFR E-10, Attachment 1, outlines the specific methodology used to develop the separation factors by each component of cost.

Q. How are load research studies used in the development of separation factors and cost of service studies?

A. Load research studies are used to develop the load, or demand-related allocation factors used in separation factors and cost of service studies. These demand-related allocation factors, namely CP, GNCP, and NCP, are adjusted to account for line losses as shown in MFR E-10 for consolidated FPL. Adjusted allocation factors are used in the separation study to allocate the rate base, revenues, and expenses between retail and wholesale customers and then in the cost of service study to allocate the retail jurisdictional rate base, revenues, and expenses to the individual retail rate classes based on the appropriate cost drivers previously approved by this Commission.

Q. What are line losses?

A. Line losses represent the amount of energy produced that is neither sold nor used by the Company. There are two types of line losses: technical and non-technical. Technical losses are inherent to the transmission and distribution of electricity and occur on generation step-up transformers, transmission lines, distribution station step-down transformers, distribution lines, distribution transformers, and secondary service to customers. Non-technical losses include electricity theft and other unaccounted-for use of energy.

Q. How are the adjustments for line losses determined?

A. FPL witness Park forecasts line losses on a total system basis. The forecasted system-wide line losses are then converted into loss adjustment factors ("loss factors") by voltage level and by rate class. MFRs E-19a, E-19b, and E-19c provide the details and results of this process. When these loss factors by rate class are applied to the corresponding rate class load/demand-related data, the resulting values are termed 12 CP, GNCP, and NCP "adjusted for losses." Load data by rate class reflecting adjustments for line losses is summarized in MFR E-9.

Q. Why is it appropriate to adjust the demand-related allocation factors for line losses?

A. As discussed earlier, the demand-related allocation factors are developed based upon the sales forecasts by rate class, which are then multiplied by ratios, or load factors, established through load research to project CP, GNCP, and NCP. However, the forecasted sales for each rate class are measured at the customer's meter, which is net of line losses that occur in delivering electricity to customers in that class. The peak demand that is imposed upon the system by each rate class is more than the amount of energy delivered at the meter due to line losses.

If all rate classes had the same level of line losses, there would be no need to adjust for the losses because the relative relationship among the rate classes would remain the same, regardless of whether the losses were netted out. However, line losses are different for rate classes served at transmission, primary distribution, and secondary distribution voltage levels and it would not be appropriate to assume that the losses are the same for the different rate classes. Transmission lines incur lower line losses as a percent of energy delivered than customers served at lower voltage levels. Primary distribution voltage losses are higher than transmission voltage losses because they include transmission losses, as well as distribution station step-down transformers and distribution line losses. Secondary distribution voltage customers incur the highest losses per unit delivered because, in addition to losses from transmission and primary distribution voltages, their losses also include losses due to transformers and secondary services. Therefore, separate loss adjustments were developed and applied to each rate class so that these differences in line losses among the rate classes are recognized.

Q. What is the significance of the type of wholesale sales relative to the development of separation factors?

A. In general, wholesale sales consist of electricity sold to other electric utilities or power marketers for resale. They consist of power sales to other utilities, which are firm, long-term sales, and opportunity sales which are non-firm and shorter in duration. Transmission service between utilities also falls under the wholesale jurisdiction regulated by the FERC. Different regulatory treatments apply to the costs and revenues associated with a wholesale sale that is a "separated sale" and a wholesale sale that is a "non-separated sale." The

Commission has historically made a distinction between separated versus non-separated wholesale power sales. As outlined in Docket No. 970001-EI, Order No. PSC-97-0262-FOF-EI (the "Separated Sales Order"), wholesale sales that are non-firm or less than one year in duration are treated as non-separated sales, and all other sales are treated as separated sales. Non-separated sales are not assigned cost responsibility through the separation process because a utility does not commit long-term capacity to such wholesale customers. Consequently, the revenues and costs associated with non-separated sales are shared by both retail and long-term firm wholesale customers.

Q. How are separated sales treated in the jurisdictional separation study?

A. Absent a request to deviate from the Separated Sales Order, the Commission has historically required that costs associated with separated sales be allocated on a system average basis and treated as wholesale for jurisdictional separation purposes. In essence, the wholesale sale is separated to remove the production plant and operating expenses (including fuel expenses) associated with the sale from the retail jurisdiction's cost responsibility.

Additionally, some separated sales are also stratified production sales contracts ("stratified contracts"). Stratified contracts are power sales from a particular type of production resource, such as base, intermediate, or peaking. The jurisdictional separation factors for separated wholesale sales including stratified contracts are calculated using the wholesale customers' load forecasts.

Q. How does the separation study account for stratified contracts?

A. Production cost responsibilities for most of the Company's sales are based on average, total production embedded costs. By comparison, the cost responsibilities for stratified wholesale sales are based on average, embedded costs for the particular type or types of production resources used to make these sales.

In order to assign the appropriate costs to stratified sales, various system production costs (*e.g.*, plant-in-service, accumulated depreciation, operation and maintenance expenses, and depreciation expenses) are assigned to specific generating units. Each generating unit is then assigned to a production strata for cost allocation purposes. For instance, production units can be intermediate, peaking, or neither (*i.e.*, base or solar). To ensure the proper portion of production costs for a particular strata are allocated to stratified contracts, separate stratified demand and energy allocators are developed. For example, the allocators for the intermediate strata include forecasted loads for all contracts except those related to the peaking strata. Conversely, the allocators for the peaking strata include forecasted loads for all contracts except those related to the intermediate strata. The creation of these new stratified allocators provides the basis for allocating costs from a specific strata.

It is important to note that when developing stratified demand allocators, the stratified contracts' forecasted loads are adjusted based on the appropriate summer capacity that coincides with their contract (*i.e.*, peaking contracts are adjusted using the summer capacity for peaking plants). This is accomplished by dividing the average 12 CP load of stratified customers by the total average monthly system stratified resource capability adjusted for reserves. The purpose of the adjustment is to account for the higher percentage of capacity needed from a particular strata to maintain proper reserve margins while allowing customers with stratified contracts to take service exclusively from a specific strata.

Following the creation of stratified allocators, stratified production separation factors are developed by blending to stratified allocators, meaning a production separation factor could be a combination of more than one non-stratified or stratified production allocator. This is because even though underlying production costs are assigned to individual production units, those costs are grouped into accounts referred to as Cost of Service IDs ("COSIDs") prior to be being assigned a separation factor. The separation factor for a certain COSID may be a blend of several different allocators to represent the various plant unit costs included in that COSID. The development of stratified allocators and subsequent blended separation factors is shown in MFR E-10, Attachment 3.

The use of stratified allocators and blended production separation factors, results in a more accurate separation of production costs between the retail and wholesale jurisdictions by appropriately reflecting the types of generation required to serve load under stratified contracts. FPL and Gulf currently have contracts for two strata, intermediate and peaking.

Q. How are wholesale transmission service contracts treated in the jurisdictional separation study?

A. Consistent with Commission Order No. PSC-I0-0153-FOF-EI in Docket No. 080677-EI, FPL has separated the costs and revenues associated with wholesale transmission service contracts that are firm and longer than one year. These wholesale contracts are separated to remove the transmission plant and operating expenses associated with the transmission service contracts from the retail jurisdiction's cost responsibility.

Revenue from short-term, non-firm wholesale transmission service contracts are credited to both retail and wholesale jurisdictions, thereby reducing the costs to serve both jurisdictions. In other words, these contracts are not assigned cost responsibility through a separation process; the retail and wholesale firm transmission customers support all of the transmission investments and costs. In exchange for supporting the investment, both the retail and wholesale firm transmission customers receive all of the revenues.

Q. Please explain how the results of the jurisdictional separation study are incorporated into the cost of service study.

A. The jurisdictional separation factors are applied on an account, or COSID, basis to the Company's total utility rate base and NOI to compute jurisdictional or retail rate base and NOI. The consolidated FPL jurisdictional results and associated factors are shown on MFR B-6 and MFR C-4. These jurisdictional separation factors are among the inputs used to calculate the consolidated FPL jurisdictional or retail-adjusted rate base and NOI reported in MFRs B-1 and C-1, respectively, sponsored by FPL witness Fuentes. The jurisdictional, or retail-adjusted, rate base and NOI are allocated to the retail rate classes in the cost of service study.

Q. How were the separation factors developed for the standalone FPL and Gulf studies?

A. There are separate load research studies, line loss studies, and load forecasts for the standalone studies based on the historical rate classes for FPL and Gulf. These studies and forecasts are used to create the standalone FPL and Gulf separation studies following the same methodologies and processes used for the consolidated FPL studies and forecasts. For comparison purposes, similar information to that described above for consolidated FPL is available for standalone FPL and standalone Gulf in Supplements 1 and 2, respectively.

IV. RETAIL COST OF SERVICE STUDY

Q. Please provide an overview of a retail cost of service study.

A. A retail cost of service study is the continuation of the jurisdictional separation study but at the retail rate class level. The cost of service study starts with the jurisdictional-adjusted rate base and NOI. To determine costs to serve each retail rate class, the various components of the jurisdictional-adjusted rate base and NOI are functionalized, classified, and allocated to the retail rate classes.

Q. Please explain the treatment of production plant in the consolidated FPL cost of service study.

A. As required by MFR E-1 and consistent with FPL's 2016 Settlement Agreement Docket No. 160021-EI, the consolidated FPL cost of service study utilizes a 12 CP and 1/13th methodology for production plant. This methodology classifies 12/13th, or approximately 92%, of costs on the basis of CP demand and 1/13th, or approximately 8%, of costs on the basis of energy. The portion classified to demand is allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses, while the portion classified to energy is allocated based on their kWh sales, adjusted for losses. Under the 12 CP and 1/13th methodology, all generating units are treated consistently based on their function (*i.e.*, production), their classification (12/13th demand and 1/13th energy), and their allocation (contribution to the system peak and kWh of energy).

Q. How are transmission costs treated in the consolidated FPL cost of service?

A. With the exception of transmission pull-offs that are required to connect transmission voltage customers to the grid, transmission costs have been allocated on the basis of 12 CP. All transmission costs classified to demand are allocated to the individual rate classes based on their 12 CP contributions, adjusted for losses. Costs associated with transmission pull-offs are classified as customer-related and allocated only to transmission voltage customers. This approach reflects the treatment of transmission plant consistent with the Settlement agreement approved in FPL's last rate case in Docket No. 160021-EI. This same treatment of transmission plant was also approved for Duke Energy Florida, Tampa Electric Company, and Gulf Power in Docket Nos. 000824-EI, 080317-EI, and 010949-EI, respectively.

Q. What methodology is used to allocate distribution costs in the FPL cost of service?

A. Unlike production and transmission plant, which serve all retail rate classes, distribution plant is often specific to particular rate classes. Metering costs, for example, are not relevant to unmetered lighting classes, such as SL-1 and OL-1. Likewise, the cost of distribution is not incurred in providing service to transmission level customers. The distribution function is a mix of several distinct sub-functions, each with its own allocation methodology. Substations and primary voltage lines are allocated based on the GNCP of customers served from the distribution system. Secondary voltage lines are allocated based on the GNCP of customers served at secondary voltage levels. Transformers are allocated based on the NCP of customers served at secondary voltage levels.

The cost of metering equipment is classified as customer-related and is allocated to rate classes based on the fully loaded cost of the meters in service for each rate class. Service drops and primary voltage pull-offs are also classified as customer-related. Primary voltage customers are allocated the cost of primary pull-offs, and secondary voltage customers are allocated the cost of service drops.

Lastly, costs specifically dedicated to lighting customers, including fixtures, poles, and conductors, are directly assigned to those rate classes.

This methodology for allocating distribution costs is consistent with the methodology proposed in FPL Docket Nos. 830465-EI, 080677-EI 120015-EI and 160021-EI.

Q. Is FPL providing a cost of service study using the minimum distribution system ("MDS") methodology?

A. Yes. As part of FPL's most recent retail base rate case Settlement Agreement approved by Commission Order No. PSC-16-0560-AS-EI in Docket No. 160021-EI, FPL agreed to provide a cost of service study that uses the MDS methodology in its next general base rate case for informational purposes. Thus, in compliance with the Settlement Agreement, FPL is submitting an MDS cost of service study in MFR format for informational purposes, which is provided as Exhibit TBD-7. Exhibit TBD-8 also provides a comparison of target revenue requirements by rate class with and without MDS.

Q. Please describe the MDS methodology used in the comparative consolidated FPL retail cost of service study submitted in this filing.

A. The MDS methodology is a different method of classifying and allocating certain distribution plant accounts. In the comparative MDS cost of service study, primary and secondary voltage level capital and operating costs are classified based on a "minimum size system" study, which identifies the portion of those costs required to serve a customer with minimum or no load, and that portion of the costs is allocated on a customer basis. The remaining portion of the costs is allocated on a demand basis, *i.e.*, based on each rate class's maximum NCP demand.

Q. Is FPL proposing the MDS methodology be used for allocating distribution costs?

A. No. As previously stated, the MDS methodology is being provided for informational purposes pursuant to the 2016 Settlement Agreement.

Q. Has FPL provided additional detail regarding the methodologies used in the retail cost of service study?

A. Yes. MFR E-10 provides details of the methodologies used in the cost of service study to allocate the various components of rate base and NOI for consolidated FPL.

Q. Which MFRs outline the functionalization, classification, and allocation of costs in the cost of service study?

A. MFRs E-4a and E-4b show the functionalization and classification of rate base and expenses by FERC account. MFRs E-3a and E-3b show the allocation of rate base and expenses by FERC account to the individual rate classes.

Q. Are the standalone FPL and Gulf cost of service studies included in the filing?

A. Yes. Separate standalone cost of service studies are included for FPL and Gulf following the same methodologies and processes used for the consolidated FPL cost of service studies. Providing these studies ensures compliance with cost of service MFRs that require comparisons of present rates and proposed rates before and after rate class consolidations. Because individual customers from Gulf are migrated to various FPL rate classes, these calculations and comparisons would not be meaningful if made using consolidated FPL data for the 2022 test year and the standalone FPL (or the standalone Gulf) data for the prior years because "present rates" do not exist for consolidated FPL. To provide a valid basis for conducting the cost of service studies "at both present and proposed rates" for the purpose of the cost of service MFR E-1, FPL has subsumed Gulf rate classes into FPL rate classes for cost allocation and rate-making purposes. This methodology yields the proper comparisons of Rate of Return by Rate Class, Increases by Rate Class, and Parity Comparisons by Rate Class at both present and proposed rates. Any additional consolidated FPL MFRs that seek information "at present rates" (*e.g.*, D-9, E-3a, E-3b, E-4a, E-4b, E-5, E-6a, E-6b, E-7, E-8, E-9, E-10, E-11, and E-12) likewise provide such information assuming that Gulf rate classes are subsumed into FPL rate classes.

This approach is consistent with the Joint Petition of Florida Power & Light Company and Gulf Power Company for Declaratory Statement or, in the Alternative, Petition for Variance that was approved by Commission Order PSC-2020-0312-PAA-EI issued in Docket No. 20200182-EI. Therefore, for comparison purposes, similar information to that described previously for consolidated FPL is available for standalone FPL and standalone Gulf in Supplements 1 and 2, respectively, as listed in exhibit TBD-2.

V. RETAIL COST OF SERVICE RESULTS

Q. What results are produced in the cost of service study?

A. The cost of service study produces specific data for each rate class including rate base, NOI, ROR, target revenue requirements, and unit costs for demand, energy, and customer charges. Target revenue requirements and unit costs serve as the initial basis in the rate design process.

Q. How do the target revenue requirements compare among demand, energy, and customer classifications?

A. Most costs recovered in base rates are fixed costs that do not vary with energy use; therefore, the majority of revenue requirements are classified as either demand or customer related. As shown on MFR E-6b, Attachment 1, $1,044 million out of $8,821 million of revenue requirements, or 12%, are classified as energy-related. More than 85% of costs recovered through base rates are fixed costs classified as demand or customer-related, including directly assigned fixed lighting costs.

Q. How is the ROR by rate class determined?

A. ROR is calculated by dividing NOI by rate base. The retail jurisdictional ROR represents the jurisdictional adjusted NOI divided by the jurisdictional adjusted rate base. The ROR for each rate class is calculated once the various components of jurisdictional adjusted rate base and jurisdictional adjusted NOI are allocated to all rate classes. ROR on a total retail and on an individual rate class level are reported in MFR E-1.

Q. How are comparisons in ROR by rate class made?

A. A measure of how a rate class's ROR compares to the total retail ROR can be computed by dividing the class ROR by the retail ROR. The resulting figure is referred to as the parity index. A rate class with a parity index of 100% would be earning the same ROR as the retail average and deemed to be precisely at parity. A rate class with a parity index of less than 100%, or below parity, would be earning a ROR that is less than the retail average ROR, while the opposite would be true for a rate class with an index above 100%.

Q. What does the consolidated FPL cost of service study show regarding the retail average ROR and the parity indices by rate class?

A. At present rates, FPL's cost of service shows a projected retail jurisdictional ROR of 5.35% for the 2022 Test Year and 4.78% for the 2023 Subsequent Year, which is the same earned ROR as shown on Line No. 12 of MFR A-1. The consolidated FPL cost of service study shows that at present rates, certain rate classes, such as RS(T)-1, are above parity, while other rate classes, such as GSLD(T)-1, GSLD(T)-2, and GSLD(T)-3 are below parity. Exhibit TBD-5 lists the ROR and relative parity index for each rate class along with the revenue requirement differential necessary to achieve full parity at present rates for the 2022 Test Year and 2023 Subsequent Year. MFR E-1 provides the details supporting these results.

Q. Please explain the other results produced in the consolidated FPL cost of service study.

A. As previously mentioned, a cost of service study also calculates revenue requirements or target revenues by rate class. Revenue requirements consist of a return on rate base plus income taxes and expenses and represent the level of revenues required to earn a particular ROR. Consistent with the Commission's filing requirements, three sets of projected revenue requirements by rate class have been developed. One set of revenue requirements, shown in MFR E-6a, is based on each rate class's projected individual ROR. The second set of revenue requirements, also presented in MFR E-6a, is based on FPL's projected retail ROR applied uniformly to each class. The third set of revenue requirements, shown in MFR E-6b, is based on FPL's requested retail ROR applied uniformly to each rate class. MFR E-6b provides the target revenue requirements by rate class and underlying unit costs for each billing determinant (*i.e.*, demand, energy, and customer) used by FPL witness Cohen in the rate development process. Exhibit TBD-6 shows target revenue requirements for each rate class at proposed rates on an equalized basis, that is, at the retail ROR or at parity. As can be seen in this exhibit, the total revenue requirements deficiency shown in Column 4 equals the amount shown on MFR A-1, line 16. The target revenue requirements shown in Column 3 are reported on MFR E-1.

The unit costs shown in MFRs E-6a and E-6b are derived by dividing the demand, energy, customer, and lighting-related revenue requirements by the appropriate billing unit. Thus, the cost of service study provides the basis to determine the demand, energy, and customer unit costs for each rate class. As stated earlier, the rate classes' target revenue requirements and underlying unit costs at the requested retail ROR serve as the initial basis in the rate design process, which FPL witness Cohen addresses.

The cost of service study in MFR E-1 also provides the impact of the proposed revenue increase on the ROR and parity index for each rate class. The proposed revenue increase by rate class used in this MFR is provided on MFR E-5, sponsored by FPL witness Cohen.

Q. Are other cost of service study results included in this filing for comparative purposes or to comply with specific guidelines?

A. Yes. As referenced in FPL witness Fuentes testimony, FPL has prepared a set of revenue requirements that do not include the Reserve Surplus Amortization Mechanism ("RSAM"). The cost of service studies that result from those revenue requirements are included in the consolidated FPL MFRs, E-1, E-3a, E-3b, E-4a, E-4b, E-6a, E-6b, and E-10, Attachments 4-6. As previously mentioned, the cost of service studies using the MDS methodology, are provided for informational purposes as Exhibit TBD-7.

Q. Should the Commission approve the consolidated FPL cost of service study?

A. Yes, the Commission should approve the proposed consolidated FPL jurisdictional separation study and the cost of service study methodology and results presented in my testimony. The methodologies used to allocate rate base, other operating revenues, and expenses between the retail and wholesale jurisdictions and among the retail rate classes were accurately applied and are consistent with those previously approved by this Commission. The use of 12 CP and 1/13th for production plant, 12 CP for transmission plant adjusted for pull-offs, and distribution plant cost of service methodologies are consistent with those previously approved by this Commission and better align costs and benefits to the customer classes. The consolidated FPL cost of service study results accurately represent the cost responsibility of all customers in the combined company.

Q. Does this conclude your direct testimony?

A. Yes.

(Whereupon, prefiled rebuttal testimony of Tara B. Dubose was inserted.)

ERRATA SHEET

WITNESS: **TARA B. DUBOSE – REBUTTAL TESTIMONY**

PAGE #	**LINE #**	**CHANGE**
7	13	Add “and designed” before “during”

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF TARA B. DUBOSE

DOCKET NO. 20210015-EI

JULY 14, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tara B. DuBose. My business address is Florida Power & Light Company ("FPL" or the "Company"), 700 Universe Boulevard, Juno Beach, Florida 33408.

Q. Did you previously submit direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits in this case?

A. Yes. I am sponsoring the following rebuttal exhibits:

- TBD-9 – Analysis of Monthly Peak Demands
- TBD-10 – FERC Three Peak Ratios Test
- TBD-11 – Target Revenue Requirements Comparison 4 CP to 12 CP

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

A. Yes. I am co-sponsoring Exhibit LF-11 – FPL's Second Notice of Identified Adjustments ("NOIAs") filed May 21, 2021 and Witness Sponsorship, which is attached to the rebuttal testimony of FPL witness Liz Fuentes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain portions of the direct testimonies of Florida Industrial Power Users Group ("FIPUG") witness Jeffery Pollock, Federal Executive Agencies ("FEA") witness Brian C. Collins, and Florida Retail Federation ("FRF") witness Tony Georgis related to FPL's cost of service study ("COSS"). Specifically, I will respond to the contentions of FRF witness

Georgis that FPL's COSS should only allocate production costs to the Commercial/Industrial Load Control ("CILC") and the Curtailable Demand Rider ("CDR") firm load and not to the non-firm or interruptible component. I will also respond to FIPUG witness Pollock's recommendation that FPL's demand-related production and transmission plant should be allocated using the 4 Coincident Peak ("CP") methodology and his assertions regarding how FPL allocates distribution costs to primary and secondary voltage level customers. Finally, I will respond to the proposal offered by each of these witnesses that FPL's distribution system costs should be allocated using a Minimum Distribution System ("MDS") cost allocation method.

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony affirms that the results of the consolidated FPL COSS submitted for the projected 2022 Test Year and 2023 Subsequent Year fairly presents each rate class's cost responsibility, rate of return ("ROR"), and parity position (*i.e.*, rate class ROR relative to system average ROR) and should be approved by the Florida Public Service Commission ("Commission") with the incorporation of FPL's NOIAs filed May 21, 2021, which are attached as Exhibit LF-11 to the rebuttal testimony of FPL witness Fuentes. The intervenors' limited criticisms of FPL's COSS allocation methods and alternative cost allocation proposals are based on flawed assumptions that do not properly reflect how FPL plans and builds its system.

My rebuttal testimony demonstrates that it is appropriate for the load assigned to CILC and CDR to be treated as firm load in the COSS, and that removing the non-firm load associated with CILC and CDR customers from COSS allocators, as suggested by FRF witness Georgis, would improperly result in a double count of the incentives provided to the CILC and CDR program customers. My rebuttal testimony also demonstrates that FPL's proposal to continue to use the 12 CP and 1/13th method for allocating production plant and the 12 CP method for allocating transmission plant is consistent with how FPL plans and builds its system and meets FERC's three peak ratios test. I will also demonstrate that the alternative allocation methodologies proposed by FIPUG witness Pollock are not appropriate and would result in significant cost shifts between rate classes. Additionally, I will show that FPL has correctly sub-functionalized distribution assets between primary and secondary voltages. Finally, I will explain that the MDS cost allocation method for distribution costs is not the best method because FPL designs and builds its distribution system to meet current and future demand (kW) load requirements, system reliability, and storm hardening requirements.

II. ALLOCATION OF CILC AND CDR INCENTIVE PAYMENTS

Q. On pages 12 through 14 of his direct testimony, FRF witness Georgis contends that FPL should have made an adjustment to the customer class demand allocators in its COSS to account for the non-firm load of the CILC and CDR customers. Do you agree with this proposed adjustment?

A. No. The production and transmission load assigned to the CILC and CDR rate classes is treated as firm load in FPL's COSS to avoid a double count of the incentives provided to the CILC and CDR program customers. As further explained in the rebuttal testimony of FPL witness Cohen, FPL treats the CILC and CDR incentive payments as additional base revenues (or revenue credits), directly offsetting the revenue requirements of customer classes that participate in these programs, because these incentive payments are collected from all customers as part of a Demand Side Management program recovered through the Energy Conservation Cost Recovery clause. Providing a revenue credit in the COSS is a more direct method of crediting the CILC and CDR rate classes for these incentive payments than adjusting demand allocators. Further, removing the non-firm load associated with CILC and CDR customers from COSS allocators, while also giving these customers revenue credits, would double count the credits and inappropriately shift costs to other customers. For these reasons, it is appropriate for the load assigned to CILC and CDR to be treated as firm load in the COSS rather than being removed from demand allocators as non-firm customer load as suggested by FRF witness Georgis.

III. USE OF THE 12 CP FOR THE ALLOCATION OF PRODUCTION AND TRANSMISSION DEMAND-RELATED COST

Q. On pages 29 through 30 and 39 through 41 of his direct testimony, FIPUG witness Pollock recommends that the Commission should adopt the 4 CP

methodology to allocate FPL's production and transmission demand-related costs. Do you agree with this recommendation?

A. No. The 4 CP method to allocate production and transmission demand-related costs is inconsistent with FPL's historical practice of using the 12 CP and 1/13th methodology to allocate production plant and the 12 CP methodology to allocate transmission plant and does not properly reflect how FPL plans and builds its system.

Q. Please explain the difference between the 12 CP method and the 4 CP method.

A. Both methods allocate demand costs to each rate class on a coincident peak or CP basis. The 12 CP method utilizes the twelve monthly coincident peak demands for each rate class whereas the 4 CP method only utilizes the top four monthly coincident peak demands for each rate class, ignoring the other eight months of peak demand. If an asset (or set of assets) is only used during the four months with the highest peak demands, then a 4 CP would be appropriate; whereas, if an asset (or set of assets) is utilized and designed to meet all twelve months of peak demand then a 12 CP is most appropriate.

Q. Is FPL's use of the 12 CP method to allocate production and transmission demand-related costs appropriate?

A. Yes. Contrary to FIPUG witness Pollock's suggestion, FPL's generation capacity is needed to serve load every month, not just four months, of the year and to meet the criteria in FPL's resource planning process.

Q. What criteria are used by FPL's generation planning to determine the amount, timing, and type of generation additions?

A. The criteria used to determine the timing of generation additions and the amount and the type of generation resources include: (1) a minimum 20% summer reserve margin; (2) loss of load probability ("LOLP") of less than 0.1 days per year; (3) a minimum 20% winter reserve margin; and (4) the economics of different types of generation to ensure the lowest average generation cost for customers. To ensure that none of the criteria fails, FPL's generation planning must also consider the possibility of losing generation due to unscheduled outages, disruptions in fuel supplies, and planned maintenance in lower load months. Maintenance can result in an elevated LOLP during higher load months because the capacity reserve is reduced during these periods. To ensure these planned outages do not violate the LOLP planning criteria, planned maintenance is scheduled during lower load months or months when other generation is not scheduled for maintenance. Thus, all twelve months of the year must be considered during system planning.

Q. FIPUG witness Pollock contends that FPL is a strongly summer peaking utility with summer peak demands that are expected to consistently be more than 20% higher than winter peak demands. Do you agree?

A. No. As shown in Exhibit TBD-9 comparing FPL's highest peak demand to the peak demands of every other month of the year for historical standalone FPL and projected consolidated FPL, there are only four to five months each year where the difference between FPL's highest peak demand and the peak demand of other months is greater than 20%. In fact, FPL's peak demands are generally consistent seven to eight months of the year due to the high temperatures that occur on FPL's system throughout much of the year. For each year shown, Exhibit TBD-9 illustrates the number of months where the margin is greater than 20%. Historically, FPL has experienced peaks from April to November that are 80% or more of the highest system peak as shown for the years 2017 - 2019. With the addition of Gulf customers, the peaks for the consolidated system for the years 2022 and 2023 are also projected to be 80% or more of the highest system peak, including the winter month of January. Additionally, for the consolidated system, the monthly peak differentials are expected to decrease due to greater load diversity as explained by FPL witness Park on pages 40 and 41 of his direct testimony. Thus, the historical data for FPL, as well as the projected changes in the peak demands for the consolidated Company, support the continued use of the 12 CP allocation method for production and transmission demand-related costs for consolidated FPL.

Q. Would it be appropriate for FPL to use 4 CP to allocate production and transmission demand-related costs?

A. No. The 4 CP proposal fails to recognize the following important considerations in setting production plant allocations: (1) generation capacity is needed to serve load every month, not just four months of the year, to meet all of the criteria previously described in FPL's resource planning process; and (2) energy use and the monthly peak demands projected for the entire year influence the type of generating units added, which drives the level of capital expenditures on FPL's system.

While the decision to add generation capacity is driven by load requirements, the type of generation capacity added (and thus the total cost of the unit additions) is influenced by the number of hours the units are expected to run for the entire year. As FPL has explained in prior Commission dockets, the "type of resources that should be added is primarily based on a determination of the resources that result in the lowest average electric rates for FPL's customers." *See* Direct Testimony of Dr. Steven R. Sim, page 5, line 23 through page 6, line 2 in Docket No. 060225-EI. If megawatt capacity were the only consideration in the generation plan, the Company's generation portfolio would consist solely of peaking units that have the lowest fixed costs.

It is equally not appropriate to allocate transmission demand-related costs based on 4 CP as the transmission system is designed and built to provide capacity needs for all twelve months of the year and not just four months. Additionally, FPL's Open Access Transmission Tariff allocates transmission costs to wholesale customers using 12 CP. Shifting retail allocations to 4 CP would create a mismatch in cost recovery between the wholesale and retail jurisdictions.

Q. Are there other concerns with using summer-only allocations for production and transmission plant as suggested by FIPUG witness Pollock?

A. Yes. Summer-only allocation methods, such as the 4 CP, do not recognize that generation and transmission are needed to serve load every month of the year. This can result in some rate classes, such as street lighting, being allocated little or no production or transmission plant even though all rate classes clearly benefit from, and rely on, the system's production resources and transmission assets.

Q. Is there a test or analysis used in the utility industry to determine the appropriateness of the allocation method for production and transmission assets?

A. Yes. The Federal Energy Regulatory Commission ("FERC"), the body that regulates the wholesale rates of electricity in interstate commerce, has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[1] FERC will allow utilities to propose an alternative to 12 CP, but the utility must demonstrate that such alternative is consistent with the utility's system planning and would not result in an over-collection of the utility's revenue requirement. In evaluating such determinations, FERC uses the three peak ratios test established in *Golden Spread Electric Coop., Inc.*, 123 FERC ¶ 61,047 at 61,249 (2008):

- Test No. 1 – On and Off-Peak Test: This test first compares the average of the coincident peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincident peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

[1] *Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities*, 61 F.R. 21540-01 at 21599, Order No. 888 (1996).

- Test No. 2 – Low-to-Annual Peak Test: Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.
- Test No. 3 – Average to Annual Peak Test: Compares the average of the twelve monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.

FPL applied FERC's three peak ratios test to its FPL standalone load data (2015-2021) and two years of consolidated FPL projected load data (2022-2023) based on load data provided in MFR E-18. The results of the three peak ratios test are presented in Exhibit TBD-10. From 2015-2021, standalone FPL meets all three FERC tests for using 12 CP for each year except 2020, where standalone FPL meets two of the three tests. From 2022-2023, the projected monthly load for consolidated FPL easily meets or exceeds the criteria for all three FERC tests. Therefore, based on the FERC three peak ratio test, it is appropriate to use the 12 CP allocation method for production and transmission demand-related costs on FPL's system.

Q. Do you have any additional observations regarding the use of 4 CP to allocate production and transmission demand-related costs?

A. Yes. FPL recalculated its proposed COSS using the 4 CP method for allocating production and transmission demand-related costs. Exhibit TBD-11 attached to my rebuttal testimony shows the impacts on target rate class revenue requirements for the 2022 Test Year. As shown on page 1 of Exhibit TBD-11, the 4 CP method would shift $74 million in target revenue requirements for the 2022 Test Year from larger commercial and industrial ("CI") customers to the residential rate class.

IV. ALLOCATION OF PRIMARY AND SECONDARY COSTS

Q. On page 46 of his direct testimony, FIPUG witness Pollock contends that there are internal inconsistencies in how FPL separated the primary and secondary investments in FERC Accounts 364-367. Do you agree?

A. No. In the proposed COSS, FPL separated investments in FERC Account Nos. 364-367 between primary and secondary voltage based on the historical functionalization of each retirement unit included in the surviving balance reports. These designations were reviewed and verified by the FPL Power Delivery business unit, and this method has been consistently applied.

Q. On page 47 of his direct testimony, FIPUG witness Pollock recommends that if the Commission rejects the MDS COSS it should nevertheless use the primary/secondary separation from the MDS study. Do you agree with this recommendation?

A. No. For the reasons I explain below, the MDS COSS is not the best method for FPL's system and, therefore, it would be inappropriate to rely on only one component of that study.

V. MINIMUM DISTRIBUTION SYSTEM STUDY

Q. FIPUG witness Pollock, FEA witness Collins, and FRF witness Georgis each recommend that the Commission adopt the MDS method to allocate FPL's

distribution system costs. Is FPL proposing a COSS using the MDS methodology?

A. No. As explained in my direct testimony, FPL submitted a COSS with the MDS methodology for informational purposes pursuant to the settlement agreement in FPL's 2016 rate case.

Q. Please explain the MDS method for allocating distribution costs.

A. The MDS method recognizes both a customer and a demand component for poles, conductors, conduit, and transformers. The MDS is meant to represent a set of distribution facilities designed to serve the zero or minimum load requirements of customers. The process to develop the MDS involves determining the level of investment in poles, conductors, conduit, and transformers required solely to connect customers to the electric system without regard to demand requirements. Once this is determined, this minimum investment is allocated to customer classes based on the number of customers. The remaining distribution costs are allocated based on customer class demand requirements.

Q. Is the MDS method the only method for allocating distribution costs?

A. No. The MDS is only one method used by some utilities for allocating distribution costs.

Q. Please explain the method FPL used in its proposed COSS for allocating distribution plant.

A. FPL classifies meters, service drops, and primary pull-offs as customer-related because these costs are incurred to connect individual customers to the distribution system. The remaining balances of distribution plant, including poles, conductors, conduit, and transformers, are classified as demand-related because they can be shared by multiple customers depending on demand requirements. Demand-related distribution is allocated among the rate classes using various measures of peak demand.

Q. Is FPL's distribution cost allocation approach consistent with how FPL plans and builds its distribution system?

A. Yes. The central criterion used in planning and building FPL's distribution system is kW load requirements.

Q. Are there drawbacks with the MDS methodology for allocating distribution costs?

Yes. Under the MDS method, the minimum system has intrinsic load carrying capacity, which means that the minimum cost is the cost to serve the average customer. As a result, there may be a risk of double counting the allocations to smaller customers with less demand than the average customer. These smaller customers could receive an allocation of the minimum size equipment through the customer component and an allocation of the demand-related costs, even though a large portion of their demand may be served by the minimum sized equipment.

Q. Are there other drawbacks to using the MDS method to allocate distribution costs to FPL's customers?

A. Yes. FPL's distribution planning must account for system reliability and the fact that distribution assets in Florida must be storm hardened. Distribution system reliability and storm hardening are not based on the number of customers connected to the system. Thus, an MDS must be appropriately tailored to account for the requirements of system reliability and storm hardening in Florida.

Q. Does the National Association of Regulatory Utility Commissioners Electric Utility Cost Allocation Manual ("NARUC Manual") require the use of the MDS method for the allocation of distribution costs?

A. No. The NARUC Manual is to be used as a guideline and is not intended to prescribe one allocation method over another. Further, the NARUC Manual recognizes that MDS is not the only way to segregate customer- and demand-related costs. Specifically, the NARUC Manual states:

> "Cost analysts disagree on how much of the demand costs should be allocated to customers when the minimum-size distribution method is used to classify distribution plant. When using this distribution method, the analyst must be aware that the minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost." (*See* page 95).

Q. If the Commission were to adopt the MDS as recommended by FIPUG witness Pollock, FEA witness Collins, and FRF witness Georgis, what would be the cost allocation impacts of the MDS method?

A. More costs would be allocated to residential customers because the residential class has a larger percentage of total customers relative to total demand. While 88% of FPL customers are residential and only 2% are CI demand customers, the residential customers account for only 60% of FPL's load while the CI demand customers account for 32%.

The impacts to revenue requirements can be seen on Exhibit TBD-8 to my direct testimony, which provides a comparison of the Proposed Target Revenue Requirements by Rate Class with and without MDS. As shown on page 1 of Exhibit TBD-8, the residential rate class would be allocated $291.5 million of additional costs in the 2022 Test Year and $316.2 million of additional costs in the 2023 Subsequent Year using MDS compared to FPL's proposed COSS. Likewise, the small general service rate class would be allocated an additional $24.9 million in 2022 and an additional $25.6 million in 2023.

As stated previously, FPL's system is designed to serve customer loads, and CI customers have significantly higher loads per customer than residential. For this reason, MDS would shift costs to residential customers.

VI. CONCLUSION

Q. Can you provide a summary of the cost shifts to the residential class that would result from the intervenors' alternate cost allocation proposals discussed in your rebuttal testimony?

A. Yes. The resulting cost shifts to the residential class for each of the intervenors' methods discussed in my rebuttal testimony are summarized below for the 2022 Test Year:

- 4 CP: $74.3 million
- MDS: $291.5 million

- 4 CP + MDS: $365.8 million

Q. Would it be appropriate for FPL to change its COSS allocations resulting in the cost shifts you summarized above?

A. No. Unlike the alternate cost allocation proposals offered by the intervenors, the cost allocation methods proposed by FPL are consistent with how FPL plans and builds its system, and the results of the consolidated FPL COSS submitted by FPL for the projected 2022 Test Year and 2023 Subsequent Year fairly presents each rate class's cost responsibility, ROR, parity position, and should be approved by the Commission with the incorporation of FPL's NOIAs filed May 21, 2021, which are attached as Exhibit LF-11 to the rebuttal testimony of FPL witness Fuentes.

Q. Does this conclude your rebuttal testimony?

A. Yes.

(Transcript continues in sequence in Volume 5.)

CERTIFICATE OF REPORTER

STATE OF FLORIDA)
COUNTY OF LEON)

I, DEBRA KRICK, Court Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED this 21st day of September, 2021.

Debbie R Krick

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH31926
EXPIRES AUGUST 13, 2024