BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In re: DOCKET NO. 20250011-EI

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

VOLUME 14
PAGES 2949 - 3200

PROCEEDINGS: HEARING

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

DATE: Monday, October 13, 2025

TIME: Commenced: 9:00 a.m.
Concluded: 5:30 p.m.

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

REPORTED BY: DEBRA R. KRICK
Court Reporter

PREMIER REPORTING
TALLAHASSEE, FLORIDA
(850) 894-0828

I N D E X

EXHIBITS

NUMBER:		ID	ADMITTED
154-162	As identified in the CEL		3027
163-170	As identified in the CEL		3087
171-183	As identified in the CEL		3164
184-187	As identified in the CEL		3198

P R O C E E D I N G S

(Transcript follows in sequence from Volume 13.)

CHAIRMAN LA ROSA: All right. Let's go ahead and grab our seats and we will jump back in it.

All right. Thank you. OPC, you are calling your next witness.

MS. WESSLING: Yes. Thank you, Mr. Chair.

OPC calls Jim Dauphinais.

CHAIRMAN LA ROSA: Mr. Dauphinais, do you mind raising your right hand?

Whereupon,

JAMES R. DAUGHINAIS

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: I do.

CHAIRMAN LA ROSA: Excellent. Great. Thank you.

Have a seat, and just turn on your mic, and you guys may start when you are ready.

MS. WESSLING: Thank you, Mr. Chair.

EXAMINATION

BY MS. WESSLING:

Q All right. Good afternoon, Mr. Dauphinais.

A Good afternoon.

Q Will you please state your name and spell your last name for the record?

A James R. Dauphinais, D-A-U-P-H-I-N-A-I-S.

Q Thank you.

And did you cause to be filed prefiled direct expert testimony in this docket on June 9th, 2025?

A Yes.

Q And do you have any corrections to your prefiled testimony?

A Yes. I have a correction of one typographical error.

Q All right. If you could please let us know what that is?

A Yes. It's on page 37, line seven, the phrase or EEA Level 2 declaration should, instead, say, or EEA Level 3 declaration.

Q Thank you.

And with that one correction, if were to ask you the same questions today, would your answers be the same?

A Yes.

MS. WESSLING: Mr. Chair, I would ask that Mr. Dauphinais' testimony be entered into the record as though read.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of James R. Dauphinais was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by
Florida Power & Light Company.
_______________________________________/

Docket No. 20250011-EI

Filed: June 9, 2025

~~**CONFIDENTIAL PER DESIGNATION OF THE COMPANY**~~

DIRECT TESTIMONY
OF
JAMES R. DAUPHINAIS
ON BEHALF
OF
THE CITIZENS OF THE STATE OF FLORIDA

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C19-2768

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Exhibit	**Title**
Exhibit JRD-1	FPL Capacity Need under Traditional 20% PRM Resource Adequacy Criterion
Exhibit JRD-2	NERC EOP-011-4 – Emergency Operations Reliability Standard
Exhibit JRD-3	Relevant excerpts from NERC 2024 Long-Term Reliability Assessment
Exhibit JRD-4	Relevant excerpts from 2024-2034 SERC Annual Long-Term Reliability Assessment Report
Exhibit JRD-5	Estimated Stochastic LOLP Analysis Results for "TYP Portfolio + 1,400 MW of Storage" adjusted to reflect FPL's Proposed Pre-Summer 2027 Resource Additions
Exhibit JRD-6	Estimated Stochastic LOLP Analysis Results without FPL's 2026 and 2027 Proposed Solar Generation Additions
Exhibit JRD-7	Estimated Stochastic LOLP Analysis Results without FPL's 2027 Proposed Solar Generation Additions
Exhibit JRD-8	Excerpts from FPL 2025 Ten-Year Site Plan
Exhibit JRD-9	FPL Discovery Responses cited to by Mr. Dauphinais

DIRECT TESTIMONY

OF

James R. Dauphinais

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO: 20250011-EI

I. INTRODUCTION

A. Background and Experience

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q. WHAT IS YOUR OCCUPATION?

I am a consultant in the field of public utility regulation and a Managing Principal of Brubaker & Associates, Inc. ("BAI"), energy, economic and regulatory consultants.

Q. ON WHOSE BEHALF ARE YOU APPEARING IN THIS PROCEEDING?

A. I am appearing on behalf of the Florida Office of Public Counsel ("OPC").

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Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. In 1983, I graduated from Hartford State Technical College with an Associate's Degree in Electrical Engineering Technology. Subsequently, I completed undergraduate studies at the University of Hartford and was awarded a Bachelor's Degree in Electrical Engineering. I have also completed graduate level courses in the study of power system analysis, power system transients, and power system protection through the Engineering Outreach Program of the University of Idaho.

Q. PLEASE DESCRIBE YOUR EXPERIENCE.

A. I have over 40 years of experience in the electric utility industry, which began with the start of my employment as an Engineering Technician in the Transmission Planning Department of the Northeast Utilities Service Company ("NU," now "Eversource Energy") in 1984. In 1990, upon the completion of my undergraduate studies in electrical engineering, I was promoted to the position of Associate Engineer within the Transmission Planning Department. By 1996, I had been promoted to the position of Senior Engineer within the Transmission Planning Department.

In the employment of NU, I was responsible for conducting thermal, voltage, and stability analyses of the NU's electric transmission system to support planning and operating decisions. This involved the use of load flow, power system stability, and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions.

In 1997, I joined the firm of BAI. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science, and business. Since my employment with the firm, I have been involved with a wide variety of electric power and electric utility issues including, but not limited, to: ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off system sales, prudency, purchased power costs, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates, and transmission line routing. I have provided expert testimony on all of the foregoing. This expert testimony has been provided to the Federal Energy Regulatory Commission ("FERC") and the utility regulatory bodies of 22 states or provinces, including the Florida Public Service Commission ("Commission" or "FPSC"). I provide further information on my education and background in Appendix A to my testimony.

Q. PLEASE ELABORATE ON YOUR EXPERIENCE WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. During my employment with NU, prior to the implementation of FERC Order Nos. 888 and 889, the transmission planning organization within whom I was employed was integrated with, and part of, the same functional organization as NU's generation planning organization. This integration led to significant involvement by transmission planning, including myself, in resource planning analyses (e.g., the analysis of the potential net benefit of retirement of existing generation resources) and resource planning in transmission planning analyses (e.g., whether to proceed with economic transmission upgrades). In addition, while employed at NU, I made significant usage of the General Electric Company Multi-Area Production Simulator ("MAPS") to analyze the generation production costs associated with various transmission operating and planning alternatives on the NU system.

Subsequently, during my employment with BAI since 1997, I have become further involved with resource planning issues, initially in support of my colleagues at BAI and later in a lead position. This work has included the review of electric utility resource plans, the review of proposed certificates of public convenience and necessity for new electric utility generation resources, the forecasting of future market prices, the forecasting of future utility rates, and the evaluation of long-term power supply options. I have conducted this work both for intervenors in regulatory proceedings and specific retail end-use customer clients of BAI who were evaluating their future power supply options. I have also been extensively involved in the development of Independent System Operator ("ISO") and Regional Transmission Organization ("RTO") - administered power markets including, but not limited to, issues related to markets for energy, operating reserves and capacity.

Q. PLEASE IDENTIFY SOME OF THE CASES IN WHICH YOU PROVIDED TESTIMONY WITH RESPECT TO RESOURCE PLANNING ISSUES.

A. In the past 20 years, I have provided testimony on resource planning and/or the prudency issues related to resource planning in Indiana Utility Regulatory Commission

("IURC") Cause No. 42643, Louisiana Public Service Commission ("LPSC") Docket No. U-30192, IURC Cause No. 43393, IURC Cause No. 43396, Colorado Public Utilities Commission ("CPUC") Docket Nos. 09A-324E and 09A-325E, IURC Cause No. 43956, IURC Cause No. 44012, New Mexico Public Regulatory Commission ("NMPRC") Case No. 13-00390-UT, NMPRC Case No. 15-00261-UT, NMPRC Case No. 17-00174-UT, NMPRC Case No. 19-00018-UT, NMPRC Case No. 19-00195-UT, NMPRC Case No. 21-00083-UT, NMPRC Case No. 23-00353-UT, Michigan Public Service Commission ("MPSC") Case No. U-21090, MPSC Case No. U-21193, FPSC Docket Nos. 20160186-EI and 20160170-EI (with respect to Scherer Unit 3 in the 2016 Gulf Power Company base rate case), FPSC Docket No. 20190061-EI (with respect to Florida Power & Light Company's SolarTogether Program and Tariff), and FPSC Docket No. 20240025-EI (with respect to proposed resource additions in the 2024 Duke Energy Florida, LLC base rate case).

In a number of these proceedings, I had extensive involvement in the review of the utility's Aurora®, EnCompass® or Strategist® resource planning analysis. In the case of EnCompass® and Strategist®, this has included either me personally running the modeling tool or having modeling runs performed under my direction and supervision by other members of the BAI team, based upon data provided by the subject utility.[1] As discussed in the Direct Testimony of Florida Power & Light Company

[1] Strategist®, which includes a module called Proview®, is a computer software tool produced by Ventyx (ABB) that allows resource planners to examine a very large number of alternative resource portfolios with the goal of identifying through an optimization algorithm the most cost-effective resource portfolio for an electric utility. It can also be used in a probabilistic mode to test the robustness (i.e., risk) of specific resource portfolios over a wide range of assumption variations. Strategist® is currently utilized, and has been utilized in the past, by many electric utilities to conduct their resource planning. Other commercial software tools that have some or all of the functionality of Strategist® include software tools such as System Optimizer®, PLEXOS®, Aurora® and EnCompass®. Of these, Aurora®, PLEXOS® and EnCompass® have become more commonly used in recent years due to their greater functionality and more robust solution technique.

("FPL" or "Company") Witness Andrew Whitley, FPL uses Aurora® to support its Integrated Resource Planning ("IRP") process.[2]

Q. DO YOU HAVE PREVIOUS EXPERIENCE WITH STOCHASTIC LOSS OF LOAD PROBABILITY ("LOLP") ANALYSIS THAT IS COMMONLY USED TO EVALUATE THE RESOURCE ADEQUACY OF ELECTRIC UTILITIES?

A. Yes. I have received past training with respect to SERVM® – a software modeling tool that was developed by Astrapé Consulting (now part of PowerGEM, LLC) to perform Stochastic LOLP analysis.[3] SERVM® is used by many utilities for LOLP analysis. In addition, I have had members of the BAI staff perform SERVM® runs under my direction and supervision for testimony I have presented before the NMPRC. Also, SERVM® is the primary modeling tool used by the Midcontinent Independent System Operator, Inc. ("MISO") for the capacity accreditation and Loss of Load Expectation ("LOLE") analysis it presents to the MISO Resource Adequacy Subcommittee and the MISO Loss of Load Expectation Working Group, both of which I regularly attend and monitor as a representative of large end-use customer groups located in Illinois, Indiana, Iowa, Louisiana, Michigan and Texas.

[2] FPL Witness Andrew Whitley Direct Testimony, p. 16. The term "Stochastic LOLP" refers specifically to the stochastic analysis presented by FPL.

[3] A stochastic analysis examines a very large number of cases where input assumptions are varied based on probability and the application of random number draws.

B. Purpose of Testimony

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I present testimony with respect to the prudence, reasonableness, and cost effectiveness of FPL's already incurred and proposed investments for the following supply-side resource projects:

- FPL's estimated $538 million investment in 7 currently under construction 74.5 MW 3-hour battery storage facilities, expected to be completed by the end of 2025 and collectively referred to by FPL as the 522 MW Northwest Florida ("NWFL") Battery Storage Project or "Gulf Battery Storage".[4]

- FPL's estimated $6.5 billion investment in the following:
  - 12 proposed 74.5 MW_{AC} solar energy centers, totaling 894 MW and expected to be completed during 2026;
  - 11 proposed 74.5 MW 4-hour battery storage facilities; 1 proposed 400 MW 4-hour battery storage facility, and 1 proposed 200 MW 4-hour battery storage facility, collectively totaling 1,419.5 MW and expected to be completed during 2026;
  - 16 proposed 74.5 MW_{AC} solar energy centers, totaling 1,192 MW and expected to be completed during 2027; and

[4] FPL Witness Andrew Whitley Exhibits AWW-5 through AWW-7; FPL Witness Tim Oliver Direct Testimony, p. 9; FPL Ten Year Site Plan 2025-2034, April 2025 ("FPL 2025 TYSP"), p. 163; and FPL Response to OPC's First Request for Production of Documents, No. 30, NEE BoD Decks, "Pimentel FPL BOD Business Review May 2024 v14F_Redacted.pdf" at Slides 27-39.

- 11 proposed 74.5 MW 4-hour battery storage facilities, totaling 819.5 MW and expected to be completed during 2027.[5]

Collectively, these projects represent the largest driver of the increase in FPL's rate base in its two proposed projected test years for this base rate proceeding (calendar years 2026 and 2027). FPL is attempting to predominately justify its proposed supply -side resource projects for 2026 and 2027 based on projected load growth and a large step increase in capacity need driven by the results of a Stochastic LOLP analysis that was performed for FPL by Energy and Environmental Economics, Inc. ("E3"). As a result, my testimony also addresses FPL's Stochastic LOLP analysis.

Beyond its proposed 2026 and 2027 supply-side resources, FPL in its Petition, testimony, and exhibits also discusses pursuing up to 1,490 MW_{AC} of additional solar energy centers and 596 MW of additional battery storage facilities in 2028 and pursuing up to 1,788 MW_{AC} of additional solar energy centers and 596 MW of additional battery storage facilities in 2029.[6] However, FPL is not at this time either requesting Commission approval for those proposed facilities or requesting cost recovery of the cost of those proposed facilities in its proposed base rates for 2026 and 2027.[7] Instead, FPL is requesting the Commission to approve a Solar and Battery Base Rate Adjustment ("SoBRA") Mechanism to allow FPL in future limited proceedings: to seek advance Commission approval of FPL-proposed 2028 and 2029 solar and battery facilities up to the aforementioned amounts, and to recover the costs of those facilities

[5] FPL Witness Andrew Whitley Direct Testimony, p. 22-28; FPL Witness Tim Oliver Direct Testimony, p. 12-20; Exhibit AWW-5; Exhibit 70-2; Exhibit 70-4; and FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx.," "Rev. Req. Detail" tab.
[6] FPL Witness Andrew Whitley Direct Testimony, p. 20, 28-30 and Exhibit AWW-6 and FPL Witness Tim Oliver Direct Testimony, p. 20-22.
[7] FPL Witness Andrew Whitley Direct Testimony, p. 30 and FPL Witness Tim Oliver Direct Testimony, p. 20-22.

through an adjustment to base rates once they are completed, provided certain criteria are met.[8]

Since FPL is not seeking approval or cost recovery for its proposed 2028 and 2029 solar energy centers and battery storage facilities in this proceeding, and since OPC recommends rejection of FPL's proposed SoBRA for 2028 and 2029 for the reasons discussed later in my testimony and in the direct testimony of OPC witness Schultz, I do not address the prudence, reasonableness, and cost effectiveness of FPL's proposed 2028 and 2029 SoBRA facilities. However, I do offer testimony on the cost-effectiveness criteria that should apply when evaluating new solar and battery facilities in the event the Commission approves a SoBRA for FPL despite OPC's direct testimony recommendation in this case.

Finally, the fact that I do not address any other particular issues in my testimony or am silent with respect to any portion of FPL's Petition or direct testimony in this proceeding should not be interpreted as an approval of any position taken by FPL.

Q. WHAT DID YOU REVIEW PRIOR TO PREPARING YOUR DIRECT TESTIMONY?

A. I reviewed FPL's petition in this proceeding along with the direct testimony and exhibits in this proceeding of FPL Witnesses Ina Laney, Tim Oliver, and Andrew Whitley. I have also reviewed FPL's responses to discovery in this proceeding regarding the issues of resource adequacy, resource planning, Investment Tax Credits ("ITCs"), Production Tax Credits ("PTCs"), FPL's 522 MW NWFL Battery Storage

[8] FPL Witness Tim Oliver Direct Testimony, p. 20-22.

Project, and FPL's 2026 and 2027 proposed solar energy centers and battery storage facilities. I also listened to, or reviewed the transcription of, the May 2025 depositions in this proceeding of FPL Witnesses Laney, Oliver, and Whitley. In addition, I listened to the May 29, 2025 deposition in this proceeding of Mr. Arne Olson, who is a Senior Partner at E3. As of the filing date of this testimony, neither Mr. Olson, nor anyone else from E3, is a witness in this proceeding on behalf of FPL. However, as discussed in the direct testimony of FPL Witness Whitley, E3 is the consultant that was engaged by FPL to assist FPL with resource adequacy issues, and E3, rather than FPL Witness Whitley, is the author of Mr. Whitley's Exhibit AWW-1.[9] I also reviewed the North American Electric Reliability Corporation ("NERC") Reliability Standards, NERC's most recent long-term reliability assessment, and SERC Reliability Corporation's ("SERC's") most recent long-term reliability assessment. Finally, I reviewed FPL's 2024 Ten-Year Site Plan ("2024 TYSP") and 2025 Ten-Year Site Plan ("2025 TYSP").

C. Summary of Conclusions and Recommendations

Q. BEFORE YOU SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS, DO YOU HAVE ANY CAVEATS YOU WOULD LIKE TO PUT ON THEM?

A. Yes. First, as I further discuss later in my testimony, the Stochastic LOLP analysis summarized in FPL Witness Whitley's Exhibit AWW-1 was not prepared by Mr. Whitley, who sponsored it, or anyone on the FPL team that reports to Mr. Whitley. It was prepared by E3, and FPL did not offer a witness from E3 to provide direct

[9] FPL Witness Andrew Whitley Direct Testimony, p. 14 and Exhibit AWW-1.

testimony on the analysis that E3 performed for FPL that is summarized in Exhibit AWW-1. In addition, during Mr. Whitley's deposition, it became apparent that neither he or anyone else on his team at FPL could likely perform the Stochastic LOLP analysis performed by E3 for FPL using E3's modeling tool, and they had no way to independently verify it.[10] While FPL ultimately offered Mr. Olson of E3 up for a May 29, 2025 deposition by the parties in this proceeding, that is not the same as having him provide direct testimony. Furthermore, in discovery it has been revealed that FPL has engaged E3 to potentially provide rebuttal testimony on its behalf.[11] For these reasons, there may be new information that comes to light later in this proceeding that could impact my conclusions and recommendations herein.

Second, FPL's economic analysis for its 2026 and 2027 proposed solar energy centers and battery storage facilities that was presented in FPL witness Whitley's direct testimony only examined the pursuit of those facilities on an "all or nothing basis." FPL did not provide economic analysis for the 2026 proposed facilities and 2027 facilities separately. Nor did FPL examine just adding all or part of the proposed 2026 and 2027 battery storage facilities without the addition of any of the proposed 2026 and 2027 solar energy centers. As a result, there is a potential for new information that comes to light later with respect to these alternatives that could impact my conclusions and recommendations herein.

Third, FPL's base case for its economic analysis for its 2026 and 2027 proposed solar energy centers and battery storage facilities was performed against a base case that cannot be realized due to lead time and supply chain limitations that FPL indicates

[10] FPL Witness Andrew Whitley May 7, 2025 Deposition Transcript, p. 33.
[11] FPL Response to FEL's Fourth Request for Production of Documents, No. 54, Exhibit C, p. 2.

limit the earliest date upon which it could bring new natural gas-fired generation online to late 2029 or 2030. Yet, FPL in its base case, also known as Case 4, assumed it could bring new combustion turbine generation online prior to the summers of 2028 and 2029. It did not provide an alternative base case that only adds battery storage facilities as necessary for resource adequacy prior to 2030. To examine such an alternative base case, Aurora® simulations would need to be performed of it. Neither BAI nor OPC have access to a license to Aurora® and, therefore, are unable to run such simulations. However, FPL would be able to run such simulations and may do so. Thus, there is also a potential for new information that comes to light later with respect to such an alternative base case that could impact my conclusions and recommendations herein. This said, as I discuss later in my testimony herein, there is evidence that FPL's current Aurora® modeling is unable to identify all of the costs FPL incurs for its existing and future solar generation investments such that any economic justification for new FPL solar generation investments should be rejected until such time FPL resolves the current modeling limitations FPL has with Aurora®.

Because new information in any of the above three areas may lead to one or more changes to my conclusions and recommendations within this testimony, it is my understanding that OPC reserves the right to file supplemental testimony to fully address the new information and the effects of that new information, if necessary.

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A. With the caveats I have given, my conclusions and recommendations can be summarized as follows:

- Under FPL's traditional *deterministic* 20% Planning Reserve Margin ("PRM") resource adequacy criterion, with no supply-side resource additions, FPL would have a need for additional capacity starting with Summer 2027.
- FPL has produced information in response to discovery that supports an immediate local reliability need for the Northwest Florida portion of its system for its 522 MW NWFL Battery Storage Project that is slated to fully enter service by the end of 2025.
- With the addition of the 522 MW NWFL Battery Energy Project, under FPL's traditional *deterministic* 20% PRM resource adequacy criterion, FPL will not have a need for additional capacity until Summer 2028.
- FPL in this proceeding is proposing to modify the way it applies its traditional *probabilistic* no more than 0.1 loss of firm load events days per year Loss of Load Probability ("LOLP") resource adequacy criterion by using a stochastic LOLP analysis that was prepared for FPL by E3.
- This change would require FPL to add the equivalent of up to 1,900 MW of combustion turbine generation additions for Summer 2027 above and beyond what its traditional *deterministic* 20% PRM resource adequacy criterion would require.

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- FPL's Stochastic LOLP analysis in this proceeding appears to be overly conservative and potentially significantly overstating FPL's capacity need for Summer 2027 and beyond because:
  - The results imply that FPL is already significantly short of capacity, but there is no evidence supporting that is the case given FPL has not declared any North American Electric Reliability Corporation ("NERC") Energy Emergency Alerts ("EEAs") on its system since 2017, FPL has not needed to shed load anytime in the past ten years and FPL is not indicating that there is either currently a resource adequacy problem on its system or that FPL expects there to be one on its system in 2026.
  - FPL's Stochastic LOLP analysis results for 2027 are not consistent with the 2026-2028 Stochastic LOLP analysis results of NERC and SERC, which indicate that the SERC-Florida Peninsula and SERC-Southeast areas only have a Normal Risk of loss of load not an Elevated Risk or a High Risk of loss of load.
  - FPL's Stochastic LOLP analysis appears to be rushed because it did not commence until late-October 2024, was completed less than one month before FPL filed its case in this proceeding, did not examine FPL's current and projected 2026 stochastic LOLP, and was not supported with direct testimony from E3.

- At least one of the assumptions in FPL's Stochastic LOLP analysis was overly conservative.
- FPL did not in a timely manner provide all of the workpapers for its Stochastic LOLP analysis despite them being requested very early in the proceeding, limiting intervenor review of the reasonableness of the analysis.
- No FPL stakeholders, including the Commission Staff and OPC, were given an opportunity to provide any input, never mind meaningful input, with respect to the assumptions utilized in the analysis despite the fact FPL has an inherent incentive to grow its rate base to increase the returns to its shareholders.

- While I believe FPL's Stochastic LOLP analysis may be potentially significantly overstating FPL's capacity need for Summer 2027, due to high level of solar generation investment on the FPL system relative to its total load and due to clear operational challenges FPL is experiencing related to that investment, which it did not detect in advance with its traditional operational and planning modeling tools, I conceptually agree that FPL should begin to utilize stochastic LOLP analysis and my expectation is that FPL needs some level of additional capacity for Summer 2027 beyond that which is indicated by its traditional 20% PRM resource adequacy criterion, but not necessarily the equivalent of up to 1,900 MW of new combustion turbine generation resources.

- Because of this, I recommend that the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding be limited in its application to FPL's 2026 and 2027 test years.
- In addition, for this reason, and the fact that FPL may have other resources available for 2028 such as Project Commodore, the reasons indicated in the direct testimony of OPC witness Bill Schultz, I recommend the Commission reject FPL's 2028 and 2029 SoBRA Mechanism proposals in this proceeding.
- I also recommend the Commission:
  - Require FPL to identify the current stochastic LOLP for its system as well as the expected stochastic LOLP for its system in 2026;
  - To the extent the LOLP value for either of those time periods is greater than 0.1 event days per year, require FPL to identify to the Commission whether there is an unreasonably high risk of a loss of load event on its system during those time periods, and, if so, identify all steps FPL is taking to minimize the likelihood of that risk being significantly greater than the normal risk that exists;
  - Require FPL to reconcile the 2027 results of its Stochastic LOLP analysis with the stochastic LOLP analysis results of the NERC 2024 Long-Term Reliability Assessment and the 2024-2034 SERC Annual Long-Term Reliability Assessment Report;
  - Require FPL, in future proceedings where it proposes to use stochastic LOLP analysis to justify resource additions to:

- Provide all FPL stakeholders a reasonable opportunity, prior and during the analysis, to provide meaningful input with respect to the assumptions being utilized in the analysis;
- Coordinate with the other utilities jurisdictional to the Commission to help ensure a consistent approach is used for stochastic LOLP analysis in Florida.
- Have the analysis subject to review from an independent third-party not affiliated with either FPL or the contractor who performed the analysis on behalf of FPL; and
- Provide direct testimony from an expert witness who either performed, or directly supervised the performance of, the analysis.

- FPL has not shown it has a need for all of its 2026 and 2027 proposed solar energy center and battery storage facility additions to meet its Stochastic LOLP analysis forecasted "perfect" capacity need for Summer 2027.
- FPL has not shown that the specific combination of 2026 and 2027 solar generation and battery storage resources it has proposed is the most cost-effective way to meet the "perfect" capacity need for 2027 that was identified by its Stochastic LOLP analysis in this proceeding.
- Due to the magnitude of the solar generation investment on FPL system, solar generation additions are no longer a good source of "perfect" capacity to meet FPL's resource adequacy needs versus other available resources such as battery storage facilities.

- Furthermore, FPL's current ability with its Aurora® modeling to account for all of the costs and challenges associated with further solar generation investment on its system is questionable.
- FPL's "perfect" capacity need for summer 2027 can be fully satisfied with FPL's 2026 and 2027 battery storage facilities alone – there is not a reliability need for FPL's proposed 2026 and 2027 solar energy center additions.
- As a result, for FPL's pursuit of its 2026 and 2027 proposed solar energy center additions to be found prudent, reasonable and cost effective, FPL needs to demonstrate there is a robust economic case for these resource additions to help ensure pursuit of them is consistent with providing reliable electric service at lowest reasonable cost.
- FPL has not performed such an economic analysis for its 2026 and 2027 proposed solar energy center additions and it is questionable whether its current Aurora® modeling could capture all of the costs associated with such additions at this time.
- For these reasons, while I do not oppose the Commission finding that FPL's pursuit of its 2026 and 2027 proposed battery storage facilities is prudent, reasonable and cost effective, I recommend that the Commission reject FPL's requested approval of its 2026 and 2027 proposed solar energy center additions and that the costs for those resource additions be removed from FPL's revenue requirement for the 2026 and 2027 projected test years in this proceeding.

- On an isolated basis, this would reduce FPL's non-fuel revenue requirement by $77.7 million in 2026 and by $153.6 million in 2027.
- Finally, if, despite my recommendation, the Commission approves a 2028 and 2029 SoBRA Mechanism for FPL in this proceeding, to the extent the SoBRA Mechanism involves pursuit of supply-side resource additions that are not substantially needed to meet a reliability need for the year they enter service (or in the immediately following six months), the portion of the additions that is in excess of what is needed to cost effectively meet the reliability should only be approved to the extent it is for the purpose of serving FPL's retail customers and has robust economic case associated with it as I have detailed in my testimony herein.

II. <u>TIMING AND AMOUNT OF FPL'S FIRM CAPACITY NEED</u>

A. Reviewing the Prudence, Reasonableness, and Cost-Effectiveness of Resource Additions

Q. PLEASE EXPLAIN HOW YOU REVIEWED THE PRUDENCE, REASONABLENESS AND COST-EFFECTIVENESS OF FPL'S ALREADY INCURRED AND PROJECTED INVESTMENTS FOR ITS 522 MW NWFL BATTERY STORAGE PROJECT AND ITS 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS.

A. I started by examining the timing of FPL's forecasted need for additional firm generation capacity and then examined FPL's forecasted economic performance for the investments.

Q. PLEASE EXPLAIN HOW THE TIMING OF FPL'S NEED FOR ADDITIONAL FIRM GENERATION CAPACITY DURING ITS PROJECTED TEST YEARS AFFECTS THE PRUDENCE, REASONABLENESS, AND COST-EFFECTIVENESS OF FPL'S PROPOSED INVESTMENTS IN THESE PROJECTS.

A. To the extent the firm generation capacity that would be provided by these projects is actually substantially needed immediately, or nearly immediately, following their entrance to service, there is a demonstrated reliability need for the firm capacity provided by them by the end of FPL's projected test years in this proceeding. Under that scenario, the pursuit of them would be consistent with providing reliable electric service at the lowest reasonable cost to FPL's customers provided the projects have a lower Cumulative Present Value Revenue Requirement ("CPVRR") within the expected life of the projects – for example, 35 years for new solar generation and 20 years for new battery storage – than other alternatives available to FPL that would provide a similar amount of firm generation capacity at a comparable level of risk.

However, if the firm generation capacity that would be provided by the projects is not substantially immediately needed, or nearly immediately needed, the pursuit of the projects in question by FPL with the timing that FPL has proposed would not necessarily be consistent with providing reliable electric service at lowest reasonable cost even if the investments are projected to provide a lower CPVRR for FPL. This is because there is not a reliability justification for the projects that makes them mandatory. Instead, they are elective. As elective projects, it would need to be demonstrated the projects are in fact for the purpose of serving FPL's customers (i.e., not for the purpose of FPL making off-system sales at wholesale). Furthermore, since projected cost savings would be the principal driver of pursuing these elective projects, it also needs to be demonstrated the projected CPVRR net benefit of the proposed projects, over alternatives to them that have an in-service date consistent with the timing of FPL's firm capacity need, is robust enough such that the investments are not speculative in nature and the balance of risk between FPL and its customers for the investments is reasonable.

Specifically, the economic analysis should exclude off-system sales margins (including any Production Tax Credits ("PTC") enabled by off-system sales), the CPVRR benefit to cost ratio for the investment over its book life should be robust (ideally 1.25 or higher, but at least 1.15), and a net CPVRR benefit from the investment be projected to be provided to customers no later than half-way through the life of the investment in question and no longer than 10 years after the investment enters service. The first criterion ensures the projects are being cost justified based on serving the load of FPL's customers rather than speculative off-system sales. The latter two criterion ensure the projects are essentially "no regrets" investments for FPL's customers.

Q. WHY IS IT IMPORTANT THAT FPL'S GENERATION OR RESOURCE INVESTMENTS THAT ARE ELECTIVE BE "NO REGRETS" INVESTMENTS FOR FPL'S CUSTOMERS?

A. It goes to the issues of the purpose of regulated electric service and the balance of risk between a utility and its customers. FPL's customers are not customers of FPL for the purpose of making speculative investments. They are customers of FPL for the purpose of receiving reliable electric service at the lowest reasonable cost. Hence, any elective investments FPL makes to provide that service needs to have a low risk and thus have "no regrets" associated with them. With respect to balancing risk, FPL is afforded an opportunity to earn its authorized return on the investments through its base rates whether or not the investments actually provide net savings for FPL's customers. Thus, to keep the balance of risk between FPL and its customers reasonable, the investments made by FPL once again must be of the "no regrets" nature.

Q. WHAT IS THE BASIS OF YOUR 1.25 AND 1.15 BENEFIT TO COST RATIO THRESHOLDS?

A. MISO requires a 20-year CPVRR Benefit to Cost Ratio of at least 1.25 for transmission projects pursued as Market Efficiency Projects ("MEP"). These are transmission projects that are solely being pursued for economic reasons.[12] PJM Interconnection, LLC ("PJM") uses the same threshold for economic-based transmission enhancements.[13] ERCOT uses a threshold benefit to cost ratio of 1.15 for such projects.

[12] MISO Tariff Attachment FF-Transmission Expansion Planning Protocol Section II (B)(e).
[13] PJM Manual 14B: PJM Region Transmission Planning Process.

Q. WHY IS IT IMPORTANT FOR AN EARLY CPVRR BREAKEVEN YEAR TO BE MET IN ADDITION TO MEETING A MINIMUM BENEFIT TO COST RATIO?

A. It complements the minimum benefit to cost ratio by addressing the issue of there being less certainty about the future as you go out in time. There is much more risk with a net benefit actually being realized from a project that is not forecasted to provide a net benefit until many years from now versus one that has a forecast net benefit in just a few years.

B. Analysis of Capacity Need under FPL's Traditional 20% PRM Criterion

Q. PLEASE EXPLAIN HOW FPL HAS HISTORICALLY DETERMINED ITS FIRM CAPACITY NEED.

A. FPL indicates that it has been applying *deterministic* and *probabilistic* criteria to ensure it has sufficient firm capacity, and, thus, resource adequacy, to meet its forecasted load under its TYSPs. The primary *deterministic* criterion that FPL uses is to carry extra summer and winter firm capacity known as Planning Reserve Margin ("PRM") in an amount equal or greater than 20% of the forecasted firm summer and winter demand of its customers.[14] The 20% PRM criterion was part of a settlement agreement that was approved by the Commission in Order No. PSC-99-2507-S-EU issued in Docket No. 981890-EU.[15]

[14] FPL Witness Andrew Whitley Direct Testimony, p. 10.
[15] FPL Witness Andrew Whitley Direct Testimony, p. 10 and FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 16.

A secondary *deterministic* criterion that FPL uses is to ensure it carries enough firm capacity from generation resources alone to provide a PRM of least 10% of the forecasted firm summer and winter demand of its customers. FPL refers to this as a Generation-only Reliability Margin ("GRM") of 10%. This secondary *deterministic* criterion, which FPL indicates it first established in 2014, essentially limits the portion of its capacity need that can be met by Demand Side Management ("DSM").[16] FPL reports that to-date the GRM criterion has not required FPL to need more firm capacity than that is necessary to meet its PRM criterion.[17] Furthermore, FPL is not aware of the Commission ever issuing an order approving FPL's GRM criterion.[18]

The *probabilistic* criterion that FPL uses is to carry sufficient extra firm summer and winter capacity to ensure the forecasted LOLP (also known as Loss of Load Expectation ("LOLE")) for its firm load is no greater than one loss of firm load event day in 10 years, or no more than 0.1 loss of firm load event days per year.[19] FPL reports this LOLP criterion is commonly used throughout the entire electric utility industry.[20] While FPL indicates this LOLP criterion is also consistent with the NERC Reliability Standards, FPL also recognizes NERC only uses the metric for measurement purposes – FPL is not aware of any entity that requires the 0.1 event days per year LOLP criterion be met.[21] FPL also recognizes that being incrementally long or short of the firm capacity necessary to produce a 0.1 event days per year LOLP, it only respectively

[16] FPL Witness Andrew Whitley Direct Testimony, p. 10-11.
[17] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 53.
[18] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 52.

[19] FPL Witness Andrew Whitley Direct Testimony, p. 10-11.
[20] FPL Witness Andrew Whitley Direct Testimony, p. 11.
[21] FPL Witness Andrew Whitley Direct Testimony, p. 11 and FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 27.

means the LOLP is incrementally less than 0.1 days per year or incrementally greater than 0.1 event days per year.[22] In other words, resource adequacy does not "fall off a cliff" when a utility is incrementally short of the capacity necessary to produce a LOLP of 0.1 days per years or less. Instead, the utility's LOLP is only incrementally higher than 0.1 event days per year and that incremental difference may be imperceptible to customers. This is not to say capacity should not be added to achieve the target of a LOLP of 0.1 event days per year or less, but rather that customers do not "fall off a cliff" when the target is not met and, as a probabilistic criterion, the criterion is meant to be met on average over a number of years.

FPL also reports it has historically performed its LOLP analysis using a software package called the Tie Line Assistance and Generation Reliability ("TIGER") program.[23] TIGER has been used by others in Florida including the Florida Reliability Coordinating Council, Inc. ("FRCC").[24] Due to functionality limitations with the TIGER program, FPL reports it typically performs TIGER LOLP analysis by only examining the peak load hour of each day of the year rather than all of the hours of a year.[25] FPL is not aware of any time when FPL's TIGER LOLP analysis identified a need for firm capacity for FPL for summer or winter that was greater than the amount of firm capacity needed for FPL to meet its 20% PRM criterion.[26] As a result, historically, the 20% PRM has been providing FPL, as well as other utilities in Florida that use the 20% PRM criterion, an extra bit of resource adequacy margin above what

[22] FPL Witness Andrew Whitely May 7, 2025 Deposition, Tr., p. 28-29.
[23] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 29.
[24] For example, *see* https://www.nerc.com/comm/PC/PAWG%20DL/FRCC.pdf.
[25] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 30-31.
[26] FPL Witness Andrew Whitley May 7, 2027 Deposition, Tr., p. 31.

would have been provided by just providing sufficient capacity to meet 0.1 event day per year LOLP based on TIGER LOLP analysis.[27]

Q. WHEN APPLYING ITS DETERMINISTIC 20% PRM CRITERION, DOES FPL CALCULATE THE FIRM CAPACITY FOR SOLAR GENERATION FACILITIES AND BATTERY STORAGE FACILITIES IN THE SAME MANNER AS IT DOES FOR ITS CONVENTIONAL GENERATION FACILITIES?

A. No. Since they are always available to provide their summer and winter rated capacity in all hours within the bounds of startup, shutdown and ramp rate constraints except when on outage, FPL determines the summer and winter firm capacity of its conventional generation facilities based on the summer and winter rated capability of those facilities. However, since solar generation output depends on the presence, level and angle of sunshine, and since battery storage facilities have limited energy available for discharge, FPL derates the summer and winter firm capacity for these resources from the rated capability for these resources. For solar generation, it has performed an analysis that accounts for the shifting of the time of its net peak[28] in summer as it has higher levels of solar generation penetration.[29] Specifically, FPL arrived at the following 2025 estimate of summer firm capacity as a percentage of nameplate capacity for new solar resources as a function of incremental solar generation added to its system starting in 2026.

[27] I came to a similar conclusion with respect to Duke Energy Florida in my direct testimony in Docket No. 20240025-EI as Duke Energy Florida reported the same phenomenon.
[28] The net peak is the peak demand placed on FPL's non-solar resources after accounting for solar generation.
[29] FPL Response to FIPUG's First Set of Interrogatories, No. 8

TABLE JRD-1

Summer
Solar
Firm Capacity Value Percentages
Under
FPL 20% PRM Criterion

Solar Firmness	Additional Solar Up to MWs
12.62%	894
5.31%	2,086
5.31%	3,576
5.31%	5,364

Source: FPL Response to FIPUG's First Set of Interrogatories, No. 8

For winter, FPL uses a small percentage on the order of 2 to 3% of nameplate MW based on the low expected energy output of solar generation at the time of FPL's winter system peak.[30]

Q. CAN YOU EXPLAIN HOW THE ABOVE TABLE FOR SUMMER WORKS?

A. Yes. The first 894 MW of solar generation added in 2026 or later receives a summer firm capacity of 12.62% of nameplate. The next 1,192 MW of solar generation receives a summer firm capacity of 5.31% of nameplate. Then, the next 1,490 MW of solar generation receives a summer firm capacity of 5.31% of nameplate, and so on.

[30] FPL 2025 TYSP at 163-165 (Schedule 8) and [30] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 18-19.

Q. WHAT DOES FPL DO WITH RESPECT TO BATTERY STORAGE FACILITIES?

A. It develops similar incremental firm capacity value percentages for its 20% PRM criterion but based on the storage time need on its system versus the hourly storage rating of the battery storage facilities.[31] Table JRD-2 below summarizes these values for total battery storage capability on the FPL system up to 3,991 MW of installed battery storage capability. Note that 470 to 991 MW block involves 3-hour storage, while all of the storage above 991 MW are assumed to be 4-hour storage.

TABLE JRD-2

Summer
Battery Storage
Firm Capacity Value Percentages
Under
FPL 20% PRM Criterion

Storage Firmness	Total Storage Up to MWs
100%	469
67%	991
80%	1,491
73%	1,991
57%	2,491
53%	2,991
50%	3,991

Source: FPL's Response to OPC's First Request for Production of Documents, No. 15, Whitley Workpaper "2025 FCV Battery FCV Duration Calculation- 500 MW Increments-CONFIDENTIAL.xlsx" at "FCV" tab

[31] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 97-98.

For winter, FPL currently uses a battery storage firm capacity value percentage of 100% under its 20% PRM criterion.[32]

Q. PLEASE EXPLAIN HOW YOU SPECIFICALLY EXAMINED THE TIMING OF FPL'S NEED FOR ADDITIONAL FIRM CAPACITY.

A. I did so first based on FPL's 20% PRM resource adequacy criterion. Specifically, I performed an analysis for FPL's 2025 TYSP using the 20% PRM criterion and the firm capacity value percentages for solar energy center and battery storage facility additions that I have summarized above. Through 2031, FPL's 2025 TYSP is identical to FPL's resource plan presented in Column "(2)" of FPL witness Andrew Whitley's Exhibit AWW-7.[33] As such, FPL's 2025 TYSP includes FPL's 522 MW NWFL Battery Storage Project, FPL's proposed 2026 and 2027 solar energy center and battery storage facility proposals in this proceeding, and FPL's projected 2028 and 2029 SoBRA solar energy center and battery storage facility additions. In my analysis, using information FPL provided in response to Staff's Seventh Set of Interrogatories, No. 142 and Schedule 8 of FPL's 2025 TYSP, I created a modified version of Schedule 7.1 of FPL's 2025 TYSP that backs out the summer firm capacity indicated in Schedule 8 of FPL's 2025 TYSP that is associated with all of the supply-side resource additions in Schedule 7.1. I then also added a column that only adds FPL's 522 MW NWFL Battery Storage, the minor combined cycle capacity uprates included in FPL's 2025 TYSP, and FPL's

[32] FPL 2025 TYSP at 163-165 (Schedule 8) and FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 97-98.
[33] FPL Witness Andrew Whitley May 7, 2025 Deposition, Tr., p. 83-84.

projected 475 MW combustion turbine addition in 2032. These results are presented in my Exhibit JRD-1.

The results show that, under FPL's traditional 20% PRM resource adequacy criterion, with no resource additions, FPL would have a need for additional firm capacity starting in Summer 2027. The results also show this need for additional firm capacity under the 20% PRM criterion is pushed off to Summer 2028 with the addition of FPL's 522 MW NWFL Battery Storage Project by the end of 2025 and the pre-Summer 2027 completion of a projected 47 MW combined cycle capacity uprate.

Note, I have not performed a similar analysis for winter by constructing an alternate version of Schedule 7.2 of FPL's 2025 TYSP because Schedule 7.2 of FPL's 2025 TYSP shows FPL's reserve margins for winter are much higher (40% or more) versus those in the summer (typically just above 20%). As such, under FPL's 20% PRM criterion, summer drives FPL's general firm capacity need rather than winter.

Q. YOUR ANALYSIS INDICATES THE 522 MW NWFL BATTERY STORAGE PROJECT WOULD BE COMPLETED BY THE END OF 2025, BUT IS NOT NEEDED TO MEET FPL'S GENERAL FIRM CAPACITY NEED UNTIL THE SUMMER 2027. HAS FPL'S IDENTIFIED ANY OTHER RELIABILITY NEED FOR THE 522 MW NWFL BATTERY STORAGE PROJECT THAT WOULD REQUIRE THE PROJECT TO BE FULLY ONLINE PRIOR TO SUMMER 2026?

A. Yes, in response to discovery, FPL's has provided information that indicates there is a local reliability need in Northwest Florida starting this coming winter for the 522 MW

NWFL Battery Storage Project.[34] In the discovery response, FPL indicates that transmission constraints, which are not expected to relieved until January 2027, could cause the Northwest Florida portion of its system to be deficient in reserves if it had a repeat of the winter peak load it experienced in December 2022.[35] The 522 MW NWFL Battery Storage Project is the interim solution FPL identified to address the issue. Given there is an immediate local reliability need and it is very likely there is no other effective supply-side resource option to meet this need that could have as quickly been pursued, FPL's decision to pursue completion prior to Winter 2025 rather than prior to Summer 2027 appears to be prudent, reasonable and cost-effective.

Q. DO THE RESULTS OF YOUR ANALYSIS OF FPL'S CAPACITY NEED USING FPL'S TRADITIONAL 20% PRM RESOURCE ADEQUACY CRITERION SUPPORT A RELIABILITY NEED FOR FPL'S PROPOSED 2026 AND 2027 SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS?

A. No. As shown in my Exhibit JRD-1, under FPL's traditional 20% PRM resource adequacy criterion, after the addition of FPL's 522 MW NWFL Battery Storage Project, FPL does not need additional firm capacity until Summer 2028. This conclusion is further supported by the "Without Proposed 2026 and 2027 Solar and

[34] FPL Response to FEL's Eighth Set of Interrogatories, Nos. 82, 83 and 84 and FPL Response to OPC's First Request for Production of Documents, No. 43 at "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1."
[35] FPL Response to OPC's First Request for Production of Documents, No. 43, "Development" folder at "Confidential – 2025 BESS – Northwest Florida Battery Storage May BOD Slides 1" at 3.

Battery Additions" column of witness Whitley's Exhibit AWW-5, that does not add any new firm capacity beyond the 522 MW NWFL Battery Storage Project until 2028.

C. Analysis of Capacity Need under FPL's Stochastic LOLP Analysis

Q. EARLIER, YOU INDICATED THAT YOU STARTED YOUR REVIEW OF FPL'S CAPACITY NEED BY PERFORMING AN ANALYSIS OF THAT NEED UNDER FPL'S TRADITIONAL 20% PRM RESOURCE ADEQUACY CRITERION. DID YOU PERFORM ADDITIONAL REVIEW AND ANALYSIS BEYOND THAT TRADITIONAL ANALYSIS?

A. Yes. FPL in this proceeding has proposed major changes to how it performs its analysis for its *probabilistic* LOLP resource adequacy criterion. This is the criterion under which capacity need is determined as the amount of capacity necessary to provide a targeted LOLE of no more than one loss of firm load event day in ten years (or no more than 0.1 loss of firm load event days per year). As I discussed earlier in my testimony, FPL has traditionally performed its LOLP analysis using TIGER with a focus on the peak load hour of each day and that TIGER analysis has not at any time in recent years required FPL to acquire more firm capacity than is necessary under its traditional 20% PRM resource adequacy criterion. FPL's specific proposal in this proceeding is to determine its capacity needs based on the results of a stochastic LOLP analysis performed by E3 on FPL's behalf using E3's proprietary Renewable Energy Capacity Planning Model ("RECAP") software package based on inputs and assumptions provided by FPL with no input from FPL's other stakeholders including, but not limited to, the Commission Staff and OPC. FPL's proposal, if adopted, would cause <u>a very</u>

<u>large 1,663 MW "perfect" capacity step increase</u> in FPL's Summer 2027 capacity need versus FPL's capacity need for Summer 2027 under its traditional 20% PRM resource adequacy criterion. To my knowledge, FPL is the first utility within Florida to propose determining its capacity needs based on a stochastic LOLP analysis.

Q. WHAT IS "PERFECT" CAPACITY?

A. "Perfect" capacity is capacity that is available at all times to produce energy up to its stated MW amount of capacity during any hour of the year with no restrictions whatsoever. As such, it is firmer than what FPL deems firm capacity under its traditional 20% PRM resource adequacy criteria. Specifically, while 100% of the seasonal-rated capability of FPL's fossil and nuclear generating facilities counts as firm capacity under FPL's 20% PRM resource adequacy criterion, based on E3's Stochastic LOLP analysis, only approximately 89% of that amount on average is "perfect" capacity.[36] So, to cure a "perfect" capacity need of 1,663 MW with new combustion turbine generation additions, those combustion turbine generator additions might need to total as much as 1,869 MW of summer rated capability depending on their expected equivalent forced outage rate and other factors that restrict the availability of those combustion turbine generators to provide energy at their rated capability during all hours of the year.[37]

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[36] Exhibit AWW-1 at 21-26 under "Thermal + Kingfisher 1/2."
[37] 1,869 MW = 1,663 MW / 89%

Q. WHAT DIFFERENTIATES STOCHASTIC LOLP ANALYSIS PERFORMED WITH A SOFTWARE PACKAGE SUCH AS E3'S RECAP VERSUS THE LOLP ANALYSIS FPL HAS HISTORICALLY PERFORMED USING THE TIGER SOFTWARE PACKAGE?

A. There are a number of differences. First, FPL's TIGER analysis only examines the peak load hour of each day of the year, while a stochastic LOLP analysis examines all hours of the year.[38] While it has historically been an appropriate simplification to just examine the peak load hour of each day, it ceases to be so once a utility system has had a large enough penetration of renewable generation (especially solar generation) that it has caused the time of the utility system's greatest demand on its conventional fossil and nuclear generation resources (and other non-renewable resources) to significantly shift from the time of the utility system's peak system demand hour (typically in the mid-afternoon in the summer) to other hours (such as summer evening hours). This demand is often referred to as the utility system's net demand and typically calculated as the utility's demand in an hour less the portion of that demand that is being supplied by solar and/or wind generation in that hour. The utility's peak level of net demand is often referred to as the utility's net peak.

Another difference highlighted by FPL is that FPL's traditional LOLP analysis with TIGER modeled expected generation unavailability based upon historic forced outage rates, resulting in a cumulative probability matrix of potential unit outages, while stochastic LOLP analysis simulates random selection of plant outages, which is generally viewed as better reflecting the unpredictable nature of unavailable generation

[38] FPL Witness Andrew Whitley Direct Testimony, p. 10-12.

as observed in normal system operations.[39] Finally, FPL highlights the ability in stochastic LOLP analysis to produce a reliability assessment that captures the natural variability in solar generation energy production due to weather conditions – another factor that cannot be readily modeled in FPL's traditional TIGER LOLP analysis.[40]

Q. ARE THERE OTHER SOFTWARE PACKAGES BESIDES E3'S RECAP THAT CAN BE USED TO PERFORM STOCHASTIC LOLP ANALYSIS?

A. I am aware of two. The first is PowerGEM, LLC's SERVM® and the other is GE Vernova's Multi-Area Reliability Simulation ("MARS®") software package.

SERVM® is used by many electric utilities, ISOs, RTOs, and reliability organizations to perform stochastic LOLP analysis. Examples of these include, but are not limited to, DTE Electric Company, MISO, Public Service Company of New Mexico ("PNM") and SERC. As noted earlier in my testimony, I have experience with the use of SERVM® for stochastic LOLP analysis. I have limited knowledge of and no experience with MARS®.

Q. HOW DO YOU RESPOND TO FPL'S PROPOSAL TO USE STOCHASTIC LOLP ANALYSIS TO DETERMINE ITS CAPACITY NEED?

A. While I conceptually agree the use of stochastic LOLP analysis is the most appropriate approach for a utility system with high levels of renewable (especially solar) generation, I have serious concerns with respect to the specific stochastic LOLP analysis that was performed by E3 for FPL based on the inputs and assumptions

[39] FPL Witness Andrew Whitley Direct Testimony, p. 13.
[40] FPL Witness Andrew Whitley Direct Testimony, p. 13-14.

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provided by FPL. Specifically, I am concerned that the Stochastic LOLP analysis that was performed may be overly conservative and as a result may be significantly overstating the amount of additional capacity FPL needs by Summer 2027 above and beyond what its traditional 20% PRM resource adequacy criterion would require in order to achieve a LOLE target of 0.1 event days per year or less.

Q. PLEASE EXPLAIN WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. There are seven reasons. First, FPL's Stochastic LOLP analysis suggests FPL is currently significantly short of capacity given that it is indicating FPL needs nearly the equivalent of 1,900 MW of new fossil generation in 2027 above and beyond what it would need under its traditional 20% PRM criterion and would have a LOLE of 0.74 event days per year (the equivalent of 7.4 event days in ten years) in 2027[41] if that amount capacity (or the "perfect" capacity equivalent of it from other types of resources) is not added. If that were true, I would have expected to have started to see more frequent FPL declarations of North America Electric Reliability Corporation ("NERC") Energy Emergency Alerts ("EEAs") under NERC Reliability Standard EOP-011-4 over the last ten years.[42]

There are three levels of NERC EEAs:

- EEA Level 1: All available generation resources in use.
- EEA Level 2: (Non-firm) load management procedure in effect.
- EEA Level 3: Firm Load interruption is imminent or in progress.[43]

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[41] Exhibit AWW-1, p. 21; FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (a).
[42] A copy of NERC Reliability Standard EOP-011-4 is provided in my Exhibit JRD-2.
[43] NERC Reliability Standard EOP-011-4 at 13-14.

Only the last of these three EEA levels involves the occurrence of a loss of firm load event. Furthermore, EEA Level 1 and EEA Level 2 are expected to occur with some level of frequency when an entity has significant demand responses and a LOLE close to 0.1 event days per year. This is because Demand Side Management ("DSM") is typically deployed during an EEA Level 1 or EEA Level 2 declaration.

The last time FPL had an EEA Level 1 declaration on its system, never mind a EEA Level 2 or EEA Level 3 declaration ~~or EEA Level 2 declaration~~, was April 28, 2017 due to FPL's expected use of DSM over its peak load that day.[44] FPL has not made any EEA Level 2 or EEA Level 3 declaration on its system since at least January 1, 2016.[45] FPL indicates it came close to making a EEA Level 1 declaration in August 2024 when its system was impacted by hot weather.[46] This said, FPL has not identified any recent year trend in either its declaration or near declaration of NERC EEAs that would suggest FPL is not carrying sufficient capacity on its system and needs a big step in increase in its capacity supply (by 1,663 MW) versus the status quo method of determining its need for capacity.

Q. WHAT IS YOUR SECOND REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. FPL has not provided any evidence that there is either currently a resource adequacy problem on its system or that it expects one in 2026. When asked in discovery whether it had any reason to believe its current Stochastic LOLE or its expected Stochastic

[44] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (d).
[45] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (e) and (f).
[46] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 350 (k).

LOLE for 2026 are in excess of 0.1 event days per year, FPL indicated it had not projected those values and "while no stochastic evaluations were performed, FPL consistently evaluates it system on operational basis."[47] Given FPL's response, FPL clearly does not believe it currently has a resource adequacy problem on its system or expects to have one in 2026. Yet, given the very large magnitude of additional capacity need FPL claims it has for 2027 based on its Stochastic LOLP analysis (above and beyond what would be needed under its traditional 20% PRM criterion) and the high stochastic LOLE of 0.74 event days per year that it has predicted for 2027 if that additional capacity is not added, I would expect FPL to be indicating that it currently has a stochastic LOLE in excess of 0.1 event days per year or at least expects a stochastic LOLE in excess of 0.1 events days per years in 2026. FPL has not done this. This leads me to further believe FPL's Stochastic LOLP analysis may be overly conservative.

Q. WHAT IS YOUR THIRD REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. Both NERC and SERC perform and report on long-term stochastic LOLP analysis of their own and neither is identifying any significant issue with Florida through 2028. Both have switched to reporting other stochastic LOLP measures than LOLE because LOLE does not provide any information with respect to the expected length or breadth of loss of load events and a LOLE result on one utility system may have a very different length and breadth than the same LOLE result on a different utility system.

[47] FPL Response to OPC's Sixteenth Set of Interrogatories, No. 351 (a), (b), and (c).

Specifically, NERC and SERC are instead reporting Loss of Load Hours ("LOLH"), the expected number of hours per year of loss of firm load, and Expected Unserved Energy ("EUE"), the expected total amount of unserved firm energy per year measured in terms of MWh or, alternatively on a normalized basis, parts per million ("ppm") of total annual system energy consumption. Using these two metrics, NERC has defined the following three risk categories:

- **High Risk:** Annual LOLH exceed 2.4 hours per year for one or more years, annual normalized EUE exceeds 20 ppm, and/or resource adequacy target(s) of regulatory authority or market operator not met.
- **Elevated Risk:** Annual LOLH is between 0.1 and 2.4 hours per year for one or more years, annual normalized EUE is non-zero but less than 20 ppm, and/or plausible scenarios of above-normal demand and/or low-resource conditions associated with a one-per-decade event indicated risk of load loss.
- **Normal Risk:** Annual LOLH is below 0.1 hours per year for all years and annual normalized EUE is negligible or zero.[48]

While NERC in its 2024 Long-Term Reliability Assessment ("LTRA") identified several areas in the U.S. with either a High Risk or an Elevated Risk over the period of 2025 through 2029, SERC-Florida Peninsula and SERC-Southeast were not among them.[49] They were categorized as having a Normal Risk.[50] For 2028, SERC-Florida Peninsula had a stochastic LOLP analysis result of a LOLH of 0.02 hours per year and

[48] NERC 2024 Long-Term Reliability Assessment, December 2024 at 11-12. A copy of the relevant excerpts from the NERC 2024 Long-Term Reliability Assessment is provided in my Exhibit JRD-3.
[49] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 6.
[50] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 6.

an EUE of 0.06 PPM.[51] SERC-Southeast had a result of a LOLH of 0.00 hours per year and an EUE of 0.00 PPM.[52] SERC, in its 2024-2034 SERC Annual Long-Term Reliability Assessment Report shows the same stochastic LOLP analysis results, which SERC indicates were produced using SERVM®.[53] There is no evidence in the NERC and SERC reports of a need for a large step increase in capacity supply for FPL in Summer 2027 in order to maintain resource adequacy. If there was a problem that required such a large step increase in FPL's capacity supply by Summer 2027, I would have expected it to also manifest itself in terms of there being at least an Elevated Risk in SERC-Florida Peninsula or SERC-Southeast in the NERC and SERC reports, not a Normal Risk.

Q. WHAT IS YOUR FOURTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My fourth reason is that the FPL Stochastic LOLP analysis appears rushed. The FPL's Stochastic LOLP analysis appears to rushed because: (i) it didn't commence until late October 2024,[54] (ii) it was not completed until less than one month before FPL made its filing February 28, 2025 filing in this proceeding,[55] (iii) it did not examine either FPL's current stochastic LOLE or expected its stochastic LOLE for 2026,[56] (iv) it did not examine the stochastic LOLE for FPL's principal base case for evaluating its 2026

[51] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 103.
[52] NERC 2024 Long-Term Reliability Assessment, December 2024, p. 107.
[53] 2024-2034 SERC Annual Long-Term Reliability Assessment Report at 16-17. A copy of the relevant excerpts from the 2024-2034 SERC Annual Long-Term Reliability Assessment Report is provided in my Exhibit JRD-4.
[54] May 29, 2025 Deposition of Arne Olson Tr., p. 32. (Errata pending).
[55] FPL Exhibit AWW-1 at 1 and FPL Response to OPC's Sixteenth Request for Production, No. 138 a. at "OPC POD 16-138-2025-01-27 FPL RA Check-In.pdf".
[56] FPL Response to OPC's Sixteenth Interrogatories, No. 351 (a), (b) and (c).

and 2027 proposed solar energy center and battery storage facility additions,[57] and (v) it was not supported with direct testimony on behalf of FPL by a witness from E3 who either performed the analysis or directly supervised its performance.[58] In my experience, there is a tendency, when performing a study on a rushed basis, to lean toward being conservative with respect to reliability when making assumptions. This increases the likelihood of the study being overly conservative. Furthermore, a rushed study is more likely to encounter errors – errors that could have contributed to an overly conservative result.

Q. WHAT IS YOUR FIFTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My fifth reason is that at least one of the assumptions that was made was overly conservative. Specifically, during the May 29, 2025 deposition of Mr. Olson, he confirmed that E3's modeling for FPL included an assumption that FPL is an electrical island.[59] This is, of course, not the case. Also, in my experience, it is not the most common practice, even for utilities that have only limited transmission access to other utility systems, to assume they are a complete electrical island. Furthermore, while Florida itself has limited transmission access to utility systems located outside of Florida, within Florida, there is a significant ability to call on neighbors. That ability

[57] FPL Response to OPC's Sixteenth Interrogatories, No. 351 (d) through (h); Staff's Third Interrogatories, No. 44 Corrected Supplemental; and Exhibit AWW-5.
[58] Instead, FPL witness Whitely sponsored the analysis as his Exhibit AWW-1 even though FPL did not perform the Stochastic LOLP analysis itself and witness Whitely did not directly supervise the performance of the Stochastic LOLP analysis by E3's personnel.
[59] May 29, 2025 Deposition of Arne Olson, Tr., p. 83-84 and 198-199. (Errata pending).

can and should be probabilistically modeled. To not model the ability at all is overly conservative.

Q. WHAT IS YOUR SIXTH REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My sixth reason is that not all of the workpapers for the Stochastic LOLP analysis were provided in a timely manner. Specifically, they were requested very early in this proceeding in OPC's First Request for Production of Documents No. 15, and FPL left the impression they had all been provided. However, during Mr. Olson's May 29, 2025 deposition, it became clear that several had not as of that time been provided including, but not limited to, the detailed workpapers for FPL's 2027 cases with and without 1,400 MW of additional battery storage added.[60] This limited intervenors' ability to independently review the assumptions and inputs used in FPL's Stochastic LOLP analysis, which is an essential part of ensuring that the results are not overly conservative.

Q. WHAT IS YOUR SEVENTH AND FINAL REASON WHY YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE?

A. My last reason is that no FPL stakeholders, including the Commission Staff or OPC, were given an opportunity to provide any input, never mind meaningful input, with respect to the assumptions utilized in the analysis. FPL inherently has an incentive to

[60] May 29, 2025 Deposition of Arne Olson, Tr., p. 68 and 208-210. (Errata pending).

grow its rate base to increase the returns to its shareholders. As such, FPL cannot be relied upon alone to root out overly conservative assumptions. Review and meaningful input from other FPL stakeholders is needed to help ensure that occurs.

Q. WHILE YOU BELIEVE FPL'S STOCHASTIC LOLP ANALYSIS MAY BE OVERLY CONSERVATIVE AND, AS A RESULT, OVERSTATING FPL'S CAPACITY NEED FOR RESOURCE ADEQUACY IN 2027, DO YOU BELIEVE SOME AMOUNT OF ADDITIONAL CAPACITY BEYOND THAT WHICH WOULD BE REQUIRED TO MEET FPL'S TRADITIONAL 20% PRM CRITERION MAY BE NECESSARY TO PROVIDE RESOURCE ADEQUACY IN 2027?

A. Yes. First, FPL is just under a 30,000 MW demand utility system, had 7,038 MW_{AC} of nameplate solar generation at the end of 2024, and currently in 2025 has a total of 7,932 MW_{AC} of such nameplate solar generation.[61] Thus, FPL has a high level of solar generation penetration that does require a move to stochastic LOLP analysis because at some point any historic conservatism that may have been inherent in its traditional 20% PRM criterion with respect to achieving a LOLE of 0.1 event days per year will eventually be washed away by the shift of FPL's greatest loss of load risk hours from the time of its system peak hour in the summer afternoon to summer evening hours due to FPL's heavy pursuit of solar generation. It is possible FPL has just reached that point such that its forecast load growth coupled with further pursuit of new solar generation will put FPL into a position that its traditional 20% PRM criterion will not

[61] FPL 2025 TYSP, p. 25, Exhibit AWW-5; FPL Witness Tim Oliver Direct Testimony, p. 5-6.

provide it with a LOLE of 0.1 event days per year or less in 2027. This said, this does not mean FPL necessarily needs 1,663 MW of additional "perfect' capacity for Summer 2027 to achieve a LOLE of 0.1 event days per year of less. As I have discussed, I am concerned FPL's stochastic LOLE analysis may be overly conservative and as a result significantly overstating the additional capacity FPL needs for Summer 2027 to achieve a LOLE of 0.1 event days per year of less.

Second, there is clear evidence that FPL is encountering challenges with the operation of its system related to its large investments in solar generation that FPL did not identify in advance from its Aurora® analysis. Specifically, E3 was not originally hired to provide a stochastic LOLP analysis to support proposed resource additions in this proceeding. E3's involvement with FPL instead has its origin in unexpected operational reserve problems that FPL encountered in Spring 2023 when lower than normal operational reserves were available during net system peak hours.[62]

FPL indicates these instances occurred during a period of higher than expected load and a high level of units on maintenance.[63] To address these problems, FPL had to scramble to react to lower reserves being available, had to postpone overhauls, and make short-term power purchases.[64] FPL later identified that its current generation overhaul planning process required modification to address solar energy generation decline in the late afternoon leading to a reduction in reserve margin during peak net demand.[65] It also at that time identified both short-term mitigations (reducing planned

[62] FPL Response to OPC's Sixteenth Interrogatories, No. 350 (h).
[63] *Id.*
[64] FPL Response to OPC's Sixteenth Request for Production of Documents, No. 138 (b), "OPC POD 16-138 – Overhaul Scheduling with Increased Solar Penetration – 0928.pdf".
[65] *Id.*

overhauls, purchasing long-term firm power, dispatch of Manatee 1 and 2 and/or increase regular DSM use when short-term solution are limited) and long-term mitigations (install batteries on a more aggressive schedule, contract new conventional generation or pursue long-term Purchase Power Agreements ("PPAs").[66] FPL at that time also identified other operational issues with solar generation including: (i) reduced margin also limiting the ability to schedule maintenance; (ii) increased daily cycling of conventional generation; (iii) solar forecasting uncertainty; and (iv) solar power swings.[67] FPL continued to work on these issues into the early part of 2024 and this eventually led to FPL engaging E3 to assist it with the operational reserves issue.[68] To perform that work, E3 constructed more sophisticated production cost modeling of the FPL system for 2027 using PLEXOS ST® and identified that FPL may need better tools to address operating reserve needs in operations and planning.[69] It was E3's PLEXOS modeling work in 2024 that uncovered what E3 believed to be "red flags" with respect to FPL's resource adequacy in 2027.[70] This led to E3 being redirected to focus on a new 5th track of work, which was to perform a stochastic LOLP analysis for FPL, beginning in the fourth quarter of 2024.[71]

In summary, FPL is experiencing operational challenges on its system due to the level of FPL's solar generation investments that were not adequately detected by FPL's Aurora® and TIGER modeling and this may be symptomatic of FPL needing

[66] *Id.*
[67] *Id.*
[68] FPL Response to Staff's Third Interrogatories, No. 35.
[69] FPL Response to OPC's Sixteenth Request for Production of Documents, No. 138 (a), "OPC POD 16-138 – FP&L Exec Briefing 2025.01.06.pdf".
[70] *Id.*; May 29, 2025 Deposition of Arne Olson, Tr., p. 36-37. (Errata pending).
[71] FPL Response to Staff's Third Interrogatories, No. 35; May 29, 2025 Deposition of Arne Olson, Tr., p. 36-37 and 51. (Errata pending).

some level of additional capacity for Summer 2027 beyond that which would be necessary to meet FPL's traditional 20% PRM criterion.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO FPL'S STOCHASTIC LOLP ANALYSIS IN THIS PROCEEDING?

A. I recommend that the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding be limited in its application to FPL's 2026 and 2027 test years. For this reason, the fact FPL may have access to other resource options for 2028 including Project Commodore, and the reasons discussed by OPC witness Schultz, I also recommend that FPL's proposed SoBRA for 2028 and 2029 should be rejected by the Commission. As I have discussed, FPL likely has some need for additional capacity beyond what is necessary to meet its traditional 20% PRM. However, as I have also discussed, it appears FPL's Stochastic LOLP analysis may be overly conservative and potentially significantly overstating the additional capacity FPL requires beyond its traditional 20% PRM criterion in order to assure resource adequacy. For this reason, in my opinion, the best course of action for the Commission to take is to limit the applicability of the capacity need identified by FPL's Stochastic LOLP analysis in this proceeding to FPL's 2026 and 2027 test years in the proceeding and to put conditions on FPL's future use of stochastic LOLP analysis to justify generation additions. Specifically, I recommend the Commission:

- Require FPL to identify the current Stochastic LOLP for its system as well as the expected Stochastic LOLP for its system in 2026;

- To the extent the LOLP value for either of those time periods is greater than 0.1 event days per year, require FPL to identify to the Commission whether there is an unreasonably high risk of a loss of load event on its system during those time periods, and, if so, identify all steps FPL is taking to minimize the likelihood of that risk being significantly greater than the normal risk that exists;
- Require FPL to reconcile the 2027 results of its Stochastic LOLP analysis with the stochastic LOLP analysis results of the NERC 2024 Long-Term Reliability Assessment and the 2024-2034 SERC Annual Long-Term Reliability Assessment Report;
- Require FPL, in future proceedings where it proposes to use stochastic LOLP analysis to justify generation additions to:
  - Provide all FPL stakeholders a reasonable opportunity, prior to and during the analysis, to provide meaningful input with respect to the assumptions being utilized in the analysis;
  - Coordinate with the other utilities jurisdictional to the Commission to help ensure a consistent approach is used for stochastic LOLP analysis in Florida.
  - Have the analysis subject to review from an independent third-party not affiliated with either FPL or the contractor who performed the analysis on behalf of FPL; and

- Provide direct testimony from an expert witness who either performed, or directly supervised the performance of, the analysis.

III. FPL'S 2026 AND 2027 SOLAR AND BATTERY ADDITIONS

Q. ASSUMING FPL DOES HAVE THE "PERFECT" CAPACITY NEED FOR 2027 THAT IT HAS IDENTIFIED IN ITS STOCHASTIC LOLP ANALYSIS IN THIS PROCEEDING, IS THAT SUFFICIENT ALONE TO SHOW THAT FPL HAS A RELIABILITY NEED FOR ITS 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITIES IN THEIR ENTIRETY?

A. No. First, the total nameplate capacity amounts of solar generation and battery storage proposed by FPL for 2026 and 2027 with in-service dates prior to Summer 2027 significantly exceed the amounts assumed in the Stochastic LOLP analysis case that FPL uses to justify the need for them from a reliability perspective ("TYP Portfolio + 1,400 of Storage," Exhibit AWW-1, page 22). Second, FPL has not provided any economic analysis showing the solar generation and battery storage additions in the amounts and proportions it has proposed for 2026 and 2027 are the most cost effective way to address the "perfect" capacity need for 2027 identified by FPL's Stochastic LOLP analysis. Furthermore, due to the large investment in solar generation that FPL has made to date on its system (7,932 MW_{AC} on nameplate basis), solar generation now only provides very limited "perfect" capacity (marginally, 17% of nameplate capacity per Exhibit AWW-1, page 22) versus other resource types such as battery storage (marginally, 76% of nameplate capacity per Exhibit AWW-1, page 22) such that solar generation is much less likely than in the past to be a cost-effective choice for meeting FPL's capacity needs. Third, the operational reserves problem FPL experienced in Spring 2023 continues to exist and challenge FPL and has also revealed that FPL's Aurora® modeling at this time is not likely able to capture all of the challenges and costs that would be associated with further investing in new solar generation. Finally, analysis I have performed, which corrects the expected in-service solar generation and battery storage resource levels for Summer and uses the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves),[72] shows that FPL's proposed 2026 and 2027 battery storage facility additions in this proceeding are alone capable of providing a stochastic LOLP analysis LOLE of 0.1 event days per year or less. FPL's proposed 2026 and 2027 solar energy center additions are not necessary for FPL to achieve a stochastic LOLP analysis LOLE of 0.1 event days per year or less for 2027.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE TOTAL NAMEPLATE CAPACITY AMOUNTS OF SOLAR GENERATION AND BATTERY STORAGE PROPOSED BY FPL FOR 2026 AND 2027 WITH IN-SERVICE DATES PRIOR TO SUMMER 2027 SIGNIFICANTLY EXCEED THE AMOUNTS ASSUMED IN THE STOCHASTIC LOLP ANALYSIS CASE THAT FPL USES TO JUSTIFY THE NEED FOR THEM FROM A RELIABILITY PERSPECTIVE.

[72] Exhibit AWW-1, p. 28.

A. For FPL's 2026 and 2027 proposed solar energy center and battery storage facility additions in this proceeding, FPL witness Laney in her revenue requirement workpapers shows a total of 1,490 MW_{AC} of the 2026 and 2027 solar resources and 1,867 MW of the 2026 and 2027 battery storage resources in service by April 2027.[73] When added to FPL's end-of-2025 utility solar total of 7,932 MW and battery storage total of 991 MW, this adds up to 9,422 MW of utility solar and 2,858 MW of battery storage. In contrast, the Stochastic LOLP analysis case that FPL uses to justify the need for them from a reliability perspective ("TYP Portfolio + 1,400 of Storage", Exhibit AWW-1 at page 22) only shows a total of 8,946 MW of utility solar and 2,391 MW of battery storage, which is lower by 476 MW of utility solar and 447 MW of battery storage.

To estimate how the additional 476 MW of utility solar generation and 447 MW of battery storage would change the Stochastic LOLP analysis results for the "TYP Portfolio + 1,400 of Storage" that are on page 22 of Exhibit AWW-1, I applied the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves) that are presented on page 28 of Exhibit AWW-1 and interpolated and extrapolated from the Stochastic LOLP analysis LOLE values for the two 2027 cases that were examined in Exhibit AWW-1.[74] The result of this estimate are shown in Exhibit JRD-5. As can be seen from that exhibit, with my revision to reflect pre-

[73] FPL Response to OPC's First Request for Production of Documents, No. 15, Laney folder, "SoBRA Revenue Requirements.xlsx", "Rev. Req. Detail" tab.
[74] Exhibit AWW-1, p. 20-22; FPL Response to OPC's First Request for Production of Documents, No. 15, Whitley folder, "2025-02-21 RA Study Workpapers.xlsx", "Loads, Capacity Short & LOLE" tab; and FPL Response to OPC's Sixteenth Interrogatories, No. 350 (a).

Summer 2027 in-service dates, I estimate that for 2027 FPL's 2026 and 2027 solar and battery storage additions would produce a "perfect" capacity surplus of 204 MW rather than a deficit of 273 MW and a stochastic LOLP analysis LOLE of 0.097 event days per year rather than one of 0.105 event days per year. As a result, not all of FPL's 2026 and 2027 proposed solar and battery storage additions in this proceeding are necessary for reliability.

Q. PLEASE FURTHER EXPLAIN YOUR CONCERN WITH RESPECT TO FPL NOT PROVIDING ANY ECONOMIC ANALYSIS SHOWING THE SOLAR GENERATION AND BATTERY STORAGE ADDITIONS IN THE AMOUNTS AND PROPORTIONS IT HAS PROPOSED FOR 2026 AND 2027 ARE THE MOST COST EFFECTIVE WAY TO ADDRESS THE "PERFECT" CAPACITY NEED FOR 2027 IDENTIFIED BY FPL'S STOCHASTIC LOLP ANALYSIS AND HOW THAT, WITH YOUR OTHER CONCERNS, LED YOU TO EXPLORING WHETHER JUST ADDING FPL'S 2026 AND 2027 PROPOSED BATTERY STORAGE ADDITIONS IS SUFFICIENT TO MEET FPL'S 2027 "PERFECT" CAPACITY NEED.

A. For FPL to demonstrate a proposed resource addition for reliability is prudent, reasonable and cost effective, it is not enough for FPL to demonstrate that the proposed resource addition will satisfy a reliability need such as resource adequacy. FPL must also show that the proposed resource addition is the most cost-effective way to address the reliability need.

In this proceeding, FPL did not use Aurora® to determine the most cost-effective way for it to make solar generation and battery storage additions in 2026 and 2027 to meet its capacity need in 2027. Instead, it performed the Aurora® analysis summarized in Exhibit AWW-5 that compared a case with its 2026 and 2027 proposed solar and battery storage additions to one that instead added new combustion turbine generation each year starting in 2028. While this provides insight with respect the cost effectiveness of FPL's 2026 and 2027 solar and battery storage versus a hypothetical scenario of pursuing new combustion turbines storage generation beginning in 2028, it provides absolutely no insight with respect to whether it would be most cost effective to meet FPL's 2027 capacity need with all solar generation, all battery storage, the combination of solar generation and battery storage that FPL proposed, or a different combination of solar generation and battery storage. Therefore, FPL has not shown its specific 2026 and 2027 proposed combination of solar generation and battery storage addition is the most cost-effective way to meet its 2027 capacity need.

This, combined with the concerns I also raised above with respect to solar generation additions no longer being a good source of "perfect" capacity for FPL, FPL's current Aurora® modeling not necessarily being able to properly capture all of the costs associated with further FPL solar generation additions, and FPL's 2026 and 2027 solar and generation additions providing more "perfect' capacity than necessary for 2027, led to me exploring whether FPL's "perfect" capacity need could be met without FPL's 2026 and 2027 proposed solar generation additions or at least without FPL's 2027 solar generation additions.

Q. PLEASE EXPLAIN HOW THIS EXPLORATION WAS PERFORMED AND HOW IT LED YOU TO CONCLUDE FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION ADDITIONS ARE NOT NECESSARY TO MEET FPL'S "PERFECT" CAPACITY NEED FOR 2027.

A. For both a case without FPL's 2026 and 2027 proposed solar generation additions and a case without just FPL's 2027 solar generation additions, I once again estimated stochastic LOLP analysis results by applying the cumulative "perfect" capacity curves for solar generation and battery storage developed in FPL's Stochastic LOLP analysis (including the interactions between the solar and battery curves) and interpolated and extrapolated from the Stochastic LOLP analysis LOLE values for the two 2027 cases that were examined in Exhibit AWW-1. The results for my case without FPL's 2026 and 2027 proposed solar generation additions is summarized in Exhibit JRD-6. The results for my case just without FPL's 2027 proposed solar generation additions is summarized in Exhibit JRD-7.

As shown in Exhibit JRD-6, for my case without FPL's 2026 and 2027 proposed solar generation additions, I estimate a "perfect' capacity deficit of only 89 MW and a stochastic LOLP analysis LOLE of 0.101 event days per year. This is sufficiently close to a LOLE of 0.1 events day per year or less to be considered resource adequate.

As shown in Exhibit JRD-7, for my case just without FPL's 2027 proposed solar generation additions, I estimate a "perfect' capacity surplus of 90 MW and a stochastic LOLP analysis LOLE of 0.098 event days per year. This is clearly a resource adequate result.

Based on these results, FPL's "perfect" capacity need for 2027 and Stochastic LOLP analysis LOLE target of 0.1 event day per year or less can be adequately met with FPL's 2026 and 2027 proposed battery storage facility additions alone. FPL's 2026 and 2027 proposed solar energy center additions are not necessary to meet this need and, thus, are not necessary for reliability. Therefore, as I discussed earlier in my testimony, demonstration of the prudence, reasonableness and cost effectiveness of FPL's 2026 and 2027 solar generation additions would require a demonstration that the economic case for those additions is robust and they are not being pursued for the purpose of making off-system sales. Specifically, with off-system sales excluded, they should provide a CPVRR breakeven within ten years of entering service and CPVRR benefit to cost ratio of at least 1.15 over their book life.

Q. HAS FPL PERFORMED ANY ECONOMIC ANALYSIS OF A CASE THAT INCLUDES ALL OF FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION AND BATTERY STORAGE ADDITIONS VERSUS A CASE THAT ONLY INCLUDES FPL'S 2026 AND 2027 PROPOSED BATTERY STORAGE ADDITIONS IN ORDER TO EVALUATE THE ROBUSTNESS OF THE ECONOMIC CASE FOR FPL'S 2026 AND 2027 PROPOSED SOLAR GENERATION ADDITIONS?

A. No, it has not provided one in either its direct testimony or its responses to discovery as of the filing date of this testimony. As a result, FPL has not shown pursuit of its proposed 2026 and 2027 solar energy center additions is prudent, reasonable, and cost-effective. Also, even if there was, for the reasons I discussed earlier in my testimony, it is questionable whether FPL's current Aurora® modeling would capture all of the costs associated with such additions at this time.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO FPL'S 2026 AND 2027 PROPOSED SOLAR ENERGY CENTER AND BATTERY STORAGE FACILITY ADDITIONS IN THIS PROCEEDING?

A. Assuming the Commission allows FPL to use FPL's Stochastic LOLP analysis in this proceeding to determine FPL's capacity need for 2027, a reliability need for FPL's 2026 and 2027 battery storage facility additions has been demonstrated such that I do not oppose finding FPL's pursuit of them is prudent, reasonable and cost effective. However, with respect to FPL's 2026 and 2027 proposed solar energy centers in this proceeding, FPL has not demonstrated that these proposed solar energy center additions are necessary for reliability or demonstrated that they have a robust economic case associated with them. In addition, as I have discussed in detail in my testimony, it does not appear FPL's current Aurora® economic modeling fully considers all of the costs associated with FPL further pursuing solar generation additions on its system. For these reasons, I recommend the Commission reject FPL's requested approval of its 2026 and 2027 proposed solar energy centers additions and exclude the costs of these proposed facilities from FPL's 2026 and 2027 projected test years in this proceeding. Based on FPL Witness Ina Laney's workpapers, this adjustment in isolation would reduce the non-fuel portion of FPL's proposed revenue requirement by $77.7 million for 2026 and $153.6 million for 2027. OPC Witness Schultz's testimony encompasses the other accounting impacts of my recommendation.

Q. EARLIER IN YOUR TESTIMONY, YOU RECOMMENDED THAT THE COMMISSION REJECT FPL'S PROPOSED SOBRA MECHANISM IN THIS PROCEEDING FOR 2028 AND 2029. IF, DESPITE YOUR RECOMMENDATION, THE COMMISSION INSTEAD DECIDES TO APPROVE A SOBRA FOR FPL FOR 2028 AND 2029, DO YOU HAVE ANY RECOMMENDATIONS WITH RESPECT TO CONDITIONING SUCH APPROVAL?

A. Yes, to the extent the SoBRA involves the pursuit of supply-side resource additions that are not fully needed to meet a reliability need for the year they enter service (or in the immediately following six months), consistent with my earlier testimony herein, the portion of the additions that is excess of what is needed to cost effectively meet the reliability need should only be approved to the extent they are for the purpose of serving FPL's retail customers and have robust economic case associated with it. As I have discussed on my testimony, for the investment to have a robust economic case it should be demonstrated that it both has a CPVRR breakeven with ten years of entering service and a CPVRR benefit to cost ratio of 1.15 or greater by the end of the book life of the investment. As I also discussed in greater detail earlier in my testimony herein, the foregoing demonstrations are necessary to help ensure the investment is consistent with providing reliable electric service at lowest reasonable cost to FPL's customers and not a speculative investment.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Qualifications of James R. Dauphinais

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A James R. Dauphinais. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017, USA.

Q PLEASE STATE YOUR OCCUPATION.

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

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I graduated from Hartford State Technical College in 1983 with an Associate's Degree in Electrical Engineering Technology. Subsequent to graduation, I was employed by the Transmission Planning Department of the Northeast Utilities Service Company[75] as an Engineering Technician.

While employed as an Engineering Technician, I completed undergraduate studies at the University of Hartford. I graduated in 1990 with a Bachelor's Degree in Electrical Engineering. Subsequent to graduation, I was promoted to the position of Associate Engineer. Between 1993 and 1994, I completed graduate level courses in the study of power system analysis, power system transients and power system

[75] In 2015, Northeast Utilities changed its name to Eversource Energy.

protection through the Engineering Outreach Program of the University of Idaho. By 1996 I had been promoted to the position of Senior Engineer.

In the employment of the Northeast Utilities Service Company, I was responsible for conducting thermal, voltage and stability analyses of the Northeast Utilities' transmission system to support planning and operating decisions. This involved the use of load flow, power system stability and production cost computer simulations. It also involved examination of potential solutions to operational and planning problems including, but not limited to, transmission line solutions and the routes that might be utilized by such transmission line solutions. Among the most notable achievements I had in this area include the solution of a transient stability problem near Millstone Nuclear Power Station, and the solution of a small signal (or dynamic) stability problem near Seabrook Nuclear Power Station. In 1993 I was awarded the Chairman's Award, Northeast Utilities' highest employee award, for my work involving stability analysis in the vicinity of Millstone Nuclear Power Station.

From 1990 to 1996, I represented Northeast Utilities on the New England Power Pool Stability Task Force. I also represented Northeast Utilities on several other technical working groups within the New England Power Pool ("NEPOOL") and the Northeast Power Coordinating Council ("NPCC"), including the 1992-1996 New York-New England Transmission Working Group, the Southeastern Massachusetts/Rhode Island Transmission Working Group, the NPCC CPSS-2 Working Group on Extreme Disturbances and the NPCC SS-38 Working Group on Interarea Dynamic Analysis. This latter working group also included participation from a number of ECAR, PJM and VACAR utilities.

From 1990 to 1995, I also acted as an internal consultant to the Nuclear Electrical Engineering Department of Northeast Utilities. This included interactions with the electrical engineering personnel of the Connecticut Yankee, Millstone and Seabrook nuclear generation stations and inspectors from the Nuclear Regulatory Commission ("NRC").

In addition to my technical responsibilities, from 1995 to 1997, I was also responsible for oversight of the day-to-day administration of Northeast Utilities' Open Access Transmission Tariff. This included the creation of Northeast Utilities' pre-FERC Order No. 889 transmission electronic bulletin board and the coordination of Northeast Utilities' transmission tariff filings prior to and after the issuance of Federal Energy Regulatory Commission ("FERC" or "Commission") FERC Order No. 888. I was also responsible for spearheading the implementation of Northeast Utilities' Open Access Same-Time Information System and Northeast Utilities' Standard of Conduct under FERC Order No. 889. During this time, I represented Northeast Utilities on the Federal Energy Regulatory Commission's "What" Working Group on Real-Time Information Networks. Later I served as Vice Chairman of the NEPOOL OASIS Working Group and Co-Chair of the Joint Transmission Services Information Network Functional Process Committee. I also served for a brief time on the Electric Power Research Institute facilitated "How" Working Group on OASIS and the North American Electric Reliability Council facilitated Commercial Practices Working Group.

In 1997 I joined the firm of Brubaker & Associates, Inc. The firm includes consultants with backgrounds in accounting, engineering, economics, mathematics, computer science and business. Since my employment with the firm, I have filed or presented testimony before the Federal Energy Regulatory Commission in Consumers Energy Company, Docket No. OA96-77-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER98-1438-000; Montana Power Company, Docket No. ER98-2382-000; Inquiry Concerning the Commission's Policy on Independent System Operators, Docket No. PL98-5-003; SkyGen Energy LLC v. Southern Company Services, Inc., Docket No. EL00-77-000; Alliance Companies, et al., Docket No. EL02-65-000, et al.; Entergy Services, Inc., Docket No. ER01-2201-000; Remedying Undue Discrimination through Open Access Transmission Service, Standard Electricity Market Design, Docket No. RM01-12-000; Midwest Independent Transmission System Operator, Inc., Docket No. ER10-1791-000; NorthWestern Corporation, Docket No. ER10-1138-001, et al.; Illinois Industrial Energy Consumers v. Midcontinent Independent System Operator, Inc., Docket No. EL15-82-000; Midcontinent Independent System Operator, Inc., Docket No. ER16-833-000; Midcontinent Independent System Operator, Inc., Docket No. ER17-284-000; and Midcontinent Independent System Operator, Inc. and Ameren Services Company Docket No. ER18-463-000. I have also filed or presented testimony before the Alberta Utilities Commission, the California Public Utilities Commission, the Colorado Public Utilities Commission, the Connecticut Department of Public Utility Control, the Florida Public Service Commission, the Idaho Public Service Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Iowa Utilities Board, the Kentucky Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the Missouri Public Service

Commission, the Montana Public Service Commission, the Nevada Public Utilities Commission, the New Mexico Public Regulation Commission, the Council of the City of New Orleans, the Oklahoma Corporation Commission, the Public Utility Commission of Texas, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Wisconsin Public Service Commission, the Wyoming Public Service Commission, Federal District Court and various committees of the Illinois, Missouri and South Carolina state legislatures. This testimony has been given regarding a wide variety of issues including, but not limited to, ancillary service rates, avoided cost calculations, certification of public convenience and necessity, class cost of service, cost allocation, fuel adjustment clauses, fuel costs, generation interconnection, interruptible rates, market power, market structure, off-system sales, prudency, purchased power costs, resource adequacy, resource planning, rate design, retail open access, standby rates, transmission losses, transmission planning, transmission rates and transmission line routing.

I have also participated on behalf of clients in the Southwest Power Pool Congestion Management System Working Group, the Alliance Market Development Advisory Group and several committees and working groups of the Midcontinent Independent System Operator, Inc. ("MISO"), including the Congestion Management Working Group; Economic Planning Users Group; Loss of Load Expectation Working Group; Market Subcommittee; Michigan Transmission Studies Task Force; Planning Subcommittee; Regional Expansion, Criteria and Benefits Working Group; Resource Adequacy Subcommittee (formerly the Supply Adequacy Working Group); and Reliability Subcommittee. I am currently a member of the MISO Advisory Committee

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in the end-use customer sector on behalf of industrial customer groups in Illinois, Louisiana, Michigan and Texas. I am also the past Chairman of the Issues/Solutions Subgroup of the MISO Revenue Sufficiency Guarantee ("RSG") Task Force.

In 2009, I completed the University of Wisconsin-Madison High Voltage Direct Current ("HVDC") Transmission course for Planners that was sponsored by MISO. I am a member of the Power and Energy Society ("PES") of the Institute of Electrical and Electronics Engineers ("IEEE").

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas; Louisville, Kentucky; and Phoenix, Arizona.

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BY MS. WESSLING:

Q Mr. Dauphinais, did your prefiled testimony docket also contain nine exhibits labeled JRD-1 through JRD-9?

A Yes.

Q And for the record, I believe those exhibits have been identified on the CEL as Exhibits 154 through 162.

A Yes.

Q Mr. Dauphinais, do you have any corrections to make to your exhibits?

A No.

Q Have you prepared a summary of your testimony?

A Yes.

Q All right. If you could please provide that at this time?

A Yes.

Good afternoon, Commissioners. My direct testimony evaluates the prudence, reasonableness and cost-effectiveness of FPL's proposed supply side additions.

My testimony first examination FPL's capacity need using FPL's traditional 20 percent planning reserve margin approach. This analysis shows that without any new resource additions, including FPL's 522-megawatt

Northwest Florida Battery Project, FPL would require additional firm capacity starting in summer of 2027. However, with FPL's pursuit of the 522-megawatt Northwest Florida Battery Storage Project by the end of 2025, as an interim solution to an immediate local reliability problem in Northwest Florida, no additional capacity will be required until the summer of 2028.

My testimony next turns to FPL's stochastic loss of load probability analysis, which projects a much larger capacity shortfall for summer 2027, nearly the equivalent of 1900 megawatts of gas-fired generation more than the 20-percent planning reserve margin results suggest.

While I agree, stochastic loss of load probability analysis is appropriate for a system with FPL's high solar presentation, I find the specific study performed for FPL by its consultant E3 appears to be overly conservative and potentially significantly overstating the true need for additional capacity. I explain that my concerns with this area are seven-fold.

First, FPL has experienced no loss of load events in the past decade, and no Energy Emergency Alerts since 2017.

Second, FPL has not calculated current stochastic loss of load probability values.

Third, NERC and SERC assessments classify Florida's risk as normal through 2028.

Fourth, FPL's analysis was rushed and completed just before its filing in this proceeding.

Fifth, assumptions in the analysis, such as treating FPL as an electrical island, are unrealistically conservative.

Sixth, not all of FPL's supporting workpapers were timely provided, limiting independent review.

And seventh, stakeholders were excluded from providing input on key assumptions in the analysis.

Finally, my testimony then turns to evaluating the specific combination of solar and battery storage projects FPL proposes for 2026 and 2027.

Even accepting FPL's claimed perfect capacity need under its stochastic loss of load analysis, I found FPL's proposed 2026 and 2027 battery storage resources alone can meet it. Hence, I found FPL's proposed solar resource additions for 2026 and 2027 are not required for reliability purposes.

I also found the economic case for them is not supported and FPL's existing AURORA modeling may not fully capture the cost and the operational challenges of solar resources.

Ultimately, my testimony recommends that the

Commission limit any capacity need demonstration from FPL's stochastic loss of load probability analysis to no more than the 2026 to 2027 period; reject FPL's proposed solar and battery rate just -- let me restate that. Reject FPL's proposed solar and battery base rate adjustment mechanism for 2028 and 2029; require stronger oversight, transparency, independent review and stakeholder involvement in any future stochastic loss probability analyses performed by FPL to justify resource additions; and finally, reject FPL's proposed solar resource additions for 2026 and 2027, which I have estimated would reduce FPL's proposed nonfuel revenue requirement in this proceeding by approximately $77.7 million in 2026 and $153.6 million in 2027.

Thank you.

Q Thank you.

MS. WESSLING: At this time, OPC tenders Mr. Dauphinais for cross-examination.

CHAIRMAN LA ROSA: Thank you.

FEL?

MR. MARSHALL: Thank you, Mr. Chairman, we do have a few questions.

CHAIRMAN LA ROSA: Sure.

EXAMINATION

BY MR. MARSHALL:

Q Mr. Dauphinais, your testimony does support FPL's 522 megawatts of battery storage to address winter loads in Northwest Florida, is that right?
A A local reliability from associated with winter into spring load.
Q And those are three-hour batteries?
A Those are three-hour batteries.
Q Is one of those local reliability needs based on constraints on the North Florida Resiliency Connection between Northwest Florida and the rest of FPL's territory?
A To the pest of my recollection, it is.
Q And that wasn't expected to be addressed until 2027?
A The long-term solution is to resolve in 2027 with transmission upgrades.
Q Did you hear Mr. Jarro testify last week that those constraints on that transmission line should be addressed by the end of this year?
A I did not.
Q If we could go to master page E63732?
A Okay.
Q Was this one of the documents you reviewed in determining the prudence of the Northwest Florida Battery Project?

A I don't know the source of this document and when it was produced in discovery.

Q Does it conclude at the end there that new four-hour batteries would provide minimal support during winter events where load is elevated for 14 plus hours?

A That's what this slide states.

Q And three-hour batteries would provide less support, is that right?

A Less, but not necessarily insufficient.

MR. MARSHALL: Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: Thank you.

FAIR?

MR. SCHEF WRIGHT: No questions. Thank you, Mr. Chairman.

CHAIRMAN LA ROSA: FEIA?

MR. MAY: No questions.

CHAIRMAN LA ROSA: Walmart?

MS. EATON: No questions.

CHAIRMAN LA ROSA: FRF?

MR. BREW: No questions.

CHAIRMAN LA ROSA: FIPUG?

MR. MOYLE: FIPUG has no questions.

CHAIRMAN LA ROSA: FPL?

MR. BURNETT: No questions.

CHAIRMAN LA ROSA: Staff?

MR. STILLER: No questions.

CHAIRMAN LA ROSA: Commissioners, are there any questions?

Seeing none, back to you, OPC, for redirect.

MS. WESSLING: Thank you. We have no redirect.

CHAIRMAN LA ROSA: Okay.

MS. WESSLING: And at this time, OPC asks that Mr. Dauphinais' prefiled -- or previously identified exhibits now be entered into the record.

CHAIRMAN LA ROSA: Is there objections? Seeing none, so moved.

(Whereupon, Exhibit Nos. 154-162 were received into evidence.)

CHAIRMAN LA ROSA: Anything else that needs to be moved into the record? Okay. Excellent.

Sir, I will go ahead and excuse you from the witness stand. Thank you, sir, for your testimony.

THE WITNESS: Thank you very much.

(Witness excused.)

CHAIRMAN LA ROSA: OPC, you can call your next witness once you guys get resettled.

MR. WATROUS: Thank you, Mr. Chairman. The OPC would like to call William Dunkel to the stand.

CHAIRMAN LA ROSA: Mr. Dunkel, do you mind raising your right hand?

Whereupon,

WILLIAM DUNKEL

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: Yes, sir.

CHAIRMAN LA ROSA: Excellent. Great. Thank you.

Feel free to get settled in there, and once your witness is ready, you may begin.

MR. WATROUS: Thank you.

EXAMINATION

BY MR. WATROUS:

Q Are you ready to begin, Mr. Dunkel?

A Hello.

Q Can you please state your full name and business address for the record?

A My name is William Dunkel. My address is 8625 Farmington Cemetery Road, Pleasant Plans, Illinois.

Q And did you cause to be filed prefiled direct expert testimony in this docket on June 9th, 2025?

A Yes.

Q Do you have any corrections to your prefiled testimony?

A Yes. We have filed prefiled errata on 7/8/2025. In addition to that, I do have one word to change on page 18, line 19, I am discussing the fact that Mr. Allis was double charging for transportation, and on line 19, it is stated as double checking. It should be double charging. That's the only change.

Q Thank you.

And if I were to ask you the same questions today that are contained in your prefiled testimony with your corrections, would your answers be the same?

A Yes.

MR. WATROUS: Mr. Chair, I would ask that Mr. Dunkel's testimony be entered into the record as though read.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of William Dunkel was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.
______________________________________/

Docket No. 20250011-EI

Filed: June 9, 2025

DIRECT TESTIMONY AND EXHIBITS

OF

WILLIAM DUNKEL

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

William Dunkel

On Behalf of the Office of Public Counsel

Before the

Florida Public Service Commission

DOCKET NO: 20250011-EI

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Dunkel. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. I am a consultant with, and the principal of, William Dunkel and Associates ("WDA"). I primarily address utility depreciation rates and dismantlement.

I addressed dismantlement costs in the prior Florida Power & Light Company's ("FPL" or "Company") proceeding, Docket No. 20210015-EI.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

A. I am the principal of William Dunkel and Associates, which was established in 1980. For over 40 years since that time, I have regularly provided consulting services in utility regulatory proceedings throughout the country. I have participated in over 300 state regulatory proceedings before over one-half of the state commissions in the United States. I provide, or have provided, services in utility regulatory proceedings to the following clients:

The Public Utility Commissions or their Staffs in these States:

Arkansas	Maryland
Arizona	Mississippi
Delaware	Missouri
District of Columbia	New Mexico
Georgia	North Carolina
Guam	Utah
Illinois	Virginia
Kansas	Washington
Maine	U.S. Virgin Islands

The Office of the Public Advocate, or its equivalent, in these States:

Alaska	Maryland
California	Massachusetts
Colorado	Michigan
Connecticut	Missouri
District of Columbia	Nebraska
Florida	New Jersey
Georgia	New Mexico
Hawaii	Ohio
Illinois	Oklahoma
Indiana	Pennsylvania
Iowa	Utah
Maine	Washington

The Department of Administration in these States:

Illinois	South Dakota
Minnesota	Wisconsin

I graduated from the University of Illinois in February 1970 with a Bachelor of Science Degree in Engineering Physics, with an emphasis on economics and other business-related subjects. In the past I was a design engineer for Sangamo Electric Company

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designing electric watt-hour meters used in the electric utility industry. I was granted patent No. 3822400 for solid-state meter pulse initiator which was used in metering.

I am a member of the Society of Depreciation Professionals. I have made presentations in the 2018 and 2011 annual meetings of the Society of Depreciation Professionals.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown on the attached Exhibit WWD-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Office of Public Counsel of the State of Florida ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purposes of my testimony are to (1) address the 2025 Dismantlement Study (Exhibit NWA-2) filed by Mr. Allis on behalf of Florida Power & Light Company ("FPL" or "Company") and (2) address the 2025 Depreciation Study (Exhibit NWA-1) filed by Mr. Allis on behalf of FPL, and (3) address the Direct Testimony filed by Ned W. Allis, and (4) address the associated qualifications, discovery responses, and other information related to the FPL 2025 Dismantlement Study and the FPL 2025 Depreciation Study and associated testimony.

Q. PLEASE DESCRIBE THE STEPS YOU TOOK TO PREPARE YOUR TESTIMONY.

A. The steps I took to prepare my testimony included the following steps:

- Reviewed the Direct Testimony filed by Ned W. Allis, the FPL 2025 Dismantlement Study and the FPL 2025 Depreciation Study and associated documents and workpapers filed in this proceeding.
- Prepared discovery requests to be issued in this proceeding as they pertain to dismantlement and depreciation, reviewed the responses, prepared follow-up discovery requests as appropriate, and reviewed responses to the follow-up discovery requests. I had to limit my discovery requests, keeping in mind the limitation on the allowable number of requests.
- Considered the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provision of the Federal Power Act ("FERC USOA") requirements.
- Considered the accepted depreciation practices, including those contained in the Public Utility Depreciation Practices published by the National Association of Regulatory Utility Commissioners ("NARUC").
- Conducted additional analyses, which are detailed in this testimony.

Q. PLEASE PROVIDE THE DEFINITION OF DEPRECIATION YOU USED.

A. Because this proceeding is for a regulated utility, I rely on the definition of depreciation in the FERC USOA Part 101, which states[1]:

[1] 18 CFR, Chapter 1, Subchapter C, Part 101(12). https://www.ecfr.gov/current/title-18/chapter-I/subchapter-C/part-101.

> 12. Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

II. <u>MR. ALLIS' DISMANTLEMENT STUDY</u>

A. <u>Mr. Allis has never been involved in the physical demolition of a production plant.</u>

Q. WHAT ISSUE WILL YOU PRESENT IN THIS SECTION?

A. Mr. Allis is a depreciation expert, but I have no reason to believe he is a dismantlement expert.

Q. MR. ALLIS IS THE SPONSOR OF, AND ONE OF THE TWO AUTHORS OF, THE 2025 DISMANTLEMENT STUDY (EXHIBIT NWA-2). IN THIS DOCUMENT, HE PRESENTS HIS ESTIMATES OF WHAT IT WILL ALLEGEDLY COST TO DISMANTLE THE VARIOUS FPL PRODUCTION UNITS. HAS MR. ALLIS EVER PARTICIPATED IN A PROJECT THAT INVOLVED THE ACTUAL PHYSICAL DISMANTLEMENT OF A PRODUCTION PLANT?

A. No. OPC's Ninth Set of Interrogatories, No. 271, part (a) requested the following information:

> Please list the 5 most recent projects in which Ned W. Allis participated which were the actual physical dismantlement of a utility-owned production unit. If none, so state. For each such project, provide the name of the unit, the location of the unit, the MW of the unit, the type of the unit (coal fired steam, combustion turbine, etc.), the name of the utility which owned the unit, and the year(s) it was physically dismantled. Fully describe Ned W. Allis' role in this physical dismantlement.

The FPL response includes the following: "Mr. Allis has not participated in a project that involved the physical dismantlement of a utility owned production unit."[2] Mr. Allis is a depreciation expert, but I have no reason to believe he is a dismantlement expert.

Q. THE COVER PAGE OF THE FPL 2025 DISMANTLEMENT STUDY IS SIGNED BY MR. ALLIS AND BRYAN P. BERRY, ALSO A VICE PRESIDENT OF GANNET FLEMING VALUATION AND RATE CONSULTANTS, LLC.[3] HAS BRYAN P. BERRY PARTICIPATED IN A PROJECT THAT INVOLVED THE ACTUAL PHYSICAL DISMANTLEMENT OF A PRODUCTION PLANT?

A. No. OPC's Thirteenth Set of Interrogatories, No. 337, part (a) requested the following information:

> Please list the 5 most recent projects in which Bryan P. Berry participated, which were the actual physical dismantlement of a utility-owned production unit. If none, so state. For each such project, provide the name of the unit, the location of the unit, the MW of the unit, the

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[2] FPL's response to OPC's Ninth Set of Interrogatories, No. 271. This response is shown on page 13 of Exhibit WWD-2.
[3] Exhibit NWA-2, Page 30 of 115.

> type of the unit (coal fired steam, combustion turbine, etc.), the name of the utility which owned the unit, and the year(s) it was physically dismantled. Fully describe Bryan P. Berry's role in this physical dismantlement.

The FPL response includes the following: "Mr. Berry has not directly participated in projects that included the physical dismantlement of a utility-owned production unit."[4]

Q. HAS GANNET FLEMING VALUATION AND RATE CONSULTANTS, LLC PARTICIPATED IN A PROJECT THAT INVOLVED THE ACTUAL PHYSICAL DISMANTLEMENT OF A UTILITY-OWNED PRODUCTION UNIT?

A. No. OPC's Ninth Set of Interrogatories, No. 271, part (b) requested the following information:

> Please list the 5 most recent projects in which the firm Gannett Fleming participated which were the actual physical dismantlement of a utility-owned production unit. If none, so state. For each such project, provide the name of the unit, the location of the unit, the MW of the unit, the type of the unit (coal fired steam, combustion turbine, etc.), the name of the utility which owned the unit, and the year(s) it was physically dismantled. Fully describe Gannett Fleming's role in this physical dismantlement.

The FPL response includes the following: "Gannett Fleming has not participated in a recent project that involved the physical dismantlement of a utility-owned production unit."[5] The response then listed only four, undated projects that

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[4] FPL's response to OPC's Thirteenth Set of Interrogatories, No. 337. This response is shown on page 35 of Exhibit WWD-2.
[5] FPL's response to OPC's Ninth Set of Interrogatories, No. 271. This response is shown on page 13 of Exhibit WWD-2.

merely "incorporated a dismantlement component." and the response does not even attempt to answer the question of "Gannett Fleming's role in this physical dismantlement."

Q. WHAT DOES THIS MEAN?

A. The FPL 2025 Dismantlement Study is co-authored by Mr. Allis and Mr. Berry. Neither one has participated in a project that involved the physical dismantlement of any production unit. It is uncertain as to how they know what methods will be used in the dismantlement, how many labor hours it will take to perform each of the dismantlement tasks for each of these production units, and what all the other dismantlement related costs will be. There is no valid reason to believe either one of them is an expert in the dismantlement of production units.

FPL is asking for $106.4 million per year from ratepayers[6] based on a document that contains estimates of what dismantlement methods Mr. Allis and Mr. Berry assume will be used, as well as estimates of how many labor hours they assume it will take to perform each of the many tasks in the dismantlement, among other things. Those estimates are authored by two people who have never participated in a project that involved the actual physical dismantlement of any production unit.

Mr. Allis is a depreciation expert, but I have no reason to believe he is a dismantlement expert. I have no reason to believe Mr. Berry is a dismantlement expert, either.

[6] Exhibit NWA-2, page 10.

B. <u>Mr. Allis' Dismantlement Study does not control how the units will be dismantled.</u>

Q. DO THE MEANS AND METHODS ASSUMED BY MR. ALLIS AND MR. BERRY IN THE DISMANTLEMENT STUDY CONTROL HOW THESE PRODUCTION UNITS WILL BE DISMANTLED?

A. No. The Dismantlement Study states the following:

> At the time FPL decides to decommission the plants, means and methods **will not be dictated to the contractor by Gannett Fleming**. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning and dismantling the plants at the lowest reasonable cost.[7] (Emphasis added).

C. <u>The purpose of the numbers in Mr. Allis' dismantlement study are to collect money from ratepayers.</u>

Q. IF THE DISMANTLEMENT STUDY DOES NOT SHOW HOW THE PRODUCTION UNITS WILL BE DISMANTLED, WHAT IS ITS PURPOSE?

A. The purpose of Mr. Allis' dismantlement study is to collect money from ratepayers. The higher the dollar amounts estimated, the more money FPL will collect from ratepayers (subject to the Commission's adjustment and approval). The dismantlement study does not control how the production units will be dismantled.

III. <u>RATEPAYERS' MONEY IS NOT WORTH ONLY 3.6% ANNUALLY.</u>

Q. WHAT ISSUE WILL YOU DISCUSS IN THIS SECTION?

A. Other witnesses in this case discuss what the cost of money is when the money is

[7] Exhibit NWA-2, page 36.

provided by investors. In the present-value calculation, which is part of the dismantlement cost studies, it is the ratepayers' money that is collected well in advance of the cost being incurred. The question is: what is the annual cost of money is when it is the ratepayers' money? The FPL witnesses say the annual cost of money is at least 7.63% a year when you are discussing investors' money, but they say the annual cost of money is 3.6% per year when you are discussing ratepayers' money. There is no valid reason for this discrepancy.

Q. COMPANY WITNESSES MR. ALLIS AND MR. FERGUSON HAVE CALCULATED A $106.4 MILLION[8] PROPOSED ANNUAL ACCRUAL FOR THE ESTIMATED FUTURE COSTS OF DISMANTLEMENT OF FPL'S NON-NUCLEAR GENERATING UNITS. HOW DOES FPL WITNESS FERGUSON EXPLAIN HIS CALCULATION OF THIS ANNUAL ACCRUAL?

A. FPL witness Mr. Ferguson states:

> The dismantlement study is fundamentally an aggregation of the forecasted cost of dismantling all of FPL's non-nuclear generating units and battery storage assets. The resulting annual accrual is a function **of the present value** of estimated future cost to dismantle each of those units or assets as compared to its forecasted reserve as of December 31, 2025.[9] (Emphasis added).

Q. WHAT IS "PRESENT VALUE"?

A. "Present Value" is:

> The discount rate is the rate of return on investment applied to the calculation of the Present Value (PV). In other words, if an investor

[8] Direct Testimony of FPL Witness Ferguson, page 17, lines 1-3 "The resulting annual dismantlement accrual is $106.4 million, of which $96.2 million relates to base rate assets."
[9] Direct Testimony of FPL Witness Ferguson, page 17, lines 11-15.

chose to accept an amount in the future over the same amount today, the discount rate would be the forgone rate of return.[10]

Q. WHAT IS AN IMPORTANT POINT?

A. The Present Value is based on a "rate of return" (not on the inflation rate). When money is taken from ratepayers, that deprives them of "the forgone rate of return."

Q. WHAT IS THE FUTURE COST IN THIS ISSUE?

A. For many production units, FPL will not incur the dismantlement costs until years, or even decades, in the future. For example, for Cape Canaveral CC Unit 5, FPL expects dismantlement costs to be incurred starting in 2063, which is over three decades in the future.[11]

For the future Cape Canaveral CC Unit 5 dismantlement cost, FPL will collect money from current ratepayers for a cost that is not expected to be incurred until more than three decades from now. Because of this thirty-year time differential, the ratepayers are deprived of "the forgone rate of return" on this money they paid in advance to FPL. The present-value calculation includes this fact in allocating the cost recovery among the different generations of ratepayers.[12]

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[10] See https://studyfinance.com/present-value. Similarly, "Present Value" is "the sum of money which if invested now at a given rate of compound interest will accumulate exactly to a specified amount at a specified future date." https://merriam-webster.com/dictionary/present value. Visited on June 2, 2025.
[11] Exhibit NWA-2, page 23.
[12] The full amount of the estimated future dismantlement cost is recovered from ratepayers, but the distribution among the different generations of ratepayers is affected.

Q. WHAT ANNUAL COST OF RATEPAYERS' MONEY DID FPL USE IN THE PRESENT-VALUE CALCULATIONS?

A. The FPL present-value calculations assume that the annual cost of money of ratepayers' money is only 3.6%.[13] For comparison, the FPL MFR claims an annual Cost of Capital of 7.63% when dealing primarily with investors' money.[14]

Q. HAS AN OPC WITNESS PROVIDED A DIFFERENT COST OF CAPITAL?

A. Yes. I understand OPC witness Mr. Lawton will recommend approximately a 6.26% annual overall Cost of Capital.[15]

Q. WHAT IS THE CORRECT ANNUAL ACCRUAL FOR FUTURE DISMANTLEMENT IF THE PRESENT VALUE IS CALCULATED ON THE BASIS THAT THE RATEPAYERS' MONEY IS WORTH APPROXIMATELY 6.26% PER YEAR?

A. The $106,426,281 annual accrual[16] for future dismantlement that FPL filed becomes $74,179,884 when the annual discount rate of 6.26% is used, with all other parts of the calculations the same as FPL filed. This is a difference of $32,246,398 in the annual accrual from what FPL filed. This extra $32 million per year in the FPL proposal is because FPL is assuming that ratepayers' money has a lower value than does other money.

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[13] Exhibit WWD-2, pages 32-33. FPL's response to OPC's Ninth Request for Production, No. 112 "2025 Study Sections Dismantlement with Formulas" under the tab "MASTER-Detail" in column "Compound Inflation."
[14] FPL MFR D (Proposed Test Year 12/31/26).
[15] 2026. See Mr. Lawton's Direct Testimony.
[16] Exhibit NWA-2, page 10.

Q. IS IT REASONABLE TO BELIEVE THAT THE RATEPAYERS' ANNUAL COST OF MONEY IS ONLY 3.6%, AS THE FPL WITNESSES ASSUMED?

A. No. One way to analyze this point is to consider that the Federal Reserve Bulletin shows that 45% percent of families carry a credit card balance. The Federal Reserve states the average interest charged on credit card balances is 22% percent. Every extra dollar that is taken from these families because of charges for dismantlement being higher than they should be is one less dollar they could have used to pay down their credit card balance, which is costing them 22% per year in interest. Stated another way, for almost one-half of all families, their marginal cost of money is at least 22% per year.

Q. WHAT ARE EXHIBITS WWD-3 AND WWD-4?

A. Exhibits WWD-3 and WWD-4 are copies of the documents from the Federal Reserve which support what I stated above. Exhibit WWD-3 shows that 45.2% of families hold a credit card balance. Exhibit WWD-4 is the Federal Reserve document showing that the average interest rate on credit card balances is 22%.

Q. WHAT DO YOU RECOMMEND ON THIS ISSUE?

A. FPL's assumptions that ratepayers' money is worth less than the open market value of money is unsupported. The open markets are available to everyone, including FPL ratepayers. Other witnesses in this proceeding are testifying that the cost of money in the open markets is much higher than 3.6%.

Q. HAVE YOU ADJUSTED THE DISMANTLEMENT STUDIES FOR THIS ISSUE?

A. Yes. I calculate the annual accrual using an annual discount rate of 6.26%.[17]

IV. MR. ALLIS DOUBLE RECOVERS FOR TRANSPORTATION COSTS.

Q. DO MR. ALLIS' DISMANTLEMENT STUDIES INCLUDE SPECIFIC LINE-ITEM CHARGES FOR THE COST OF TRANSPORTING SCRAP MATERIALS TO THE SALVAGE YARD?

A. Yes. Mr. Allis' dismantlement studies contain separate line items for the cost of transporting scrap from the dismantlement site to the salvage yard. For one example, in the "Okeechobee Dismantlement Cost Estimate" file for Unit 1, under "Structural Steel," Mr. Allis includes a charge of $59.24 per ton for transporting scrap "Structural Steel" from the dismantlement site to the scrap yard.[18]

Q. DOES MR. ALLIS ALSO CHARGE RATEPAYERS A SECOND TIME FOR TRANSPORTING THAT SCRAP STRUCTURAL STEEL?

A. Yes. Although Mr. Allis is charging ratepayers $59.24 per ton to transport scrap structural steel, he also reduced the price of the scrap steel because of the cost of transportation. This is a double charge.

Mr. Allis' workpapers show he knew that the current market scrap value of

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[17] To understand how this works, if I would have used a higher % discount rate, the resulting annual accrual would be a lower dollar amount than I am filing.

[18] This response is shown on page 8 of Exhibit WWD-2. "$26,007.98 /439 tons = $59.24 per ton. FPL's response to OPC's First Request for Production of Documents, No. 15, "Okeechobee Dismantlement Cost Estimate" (Tab labeled "Unit 1," Lines 171 to 173).

"Structural Steel" was $315 per ton.[19] However, in his dismantlement study he used a reduced scrap value for "Structural Steel" of $160 per ton. In his workpapers. Mr. Allis explains the reasons he reduced the credit from the market price of $315 per ton, to the $160 he used is to "account for **transportation**, contamination and other factors."[20] (Emphasis added).

Mr. Allis' proposal charges ratepayers twice for the cost of transporting scrap to the salvage yard. The cost of transporting the scrap to the salvage yard is a line item in his dismantlement study, but he also reduces the price of the scrap used in his dismantlement study for the cost of transporting the scrap. That is a proposed double charge.

Q. HAVE YOU MADE A SPECIFIC SEPARATE ADJUSTMENT TO REMOVE MR. ALLIS' DOUBLE CHARGE FOR TRANSPORTATION?

A. No. I have not made a specific adjustment for Mr. Allis' double charging for transportation, but I did consider it and other issues when making my contingency recommendation, which is discussed later in this testimony.

V. MR. ALLIS' SOLAR DISMANTLEMENT STUDY

Q. ARE MR. ALLIS' SOLAR DISMANTLEMENT STUDIES PARTICULARLY SIGNIFICANT?

[19] Exhibit WWD-2, page 21. FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109 "FPL Steel Scrap Price Analysis" (under the "Current" price).
[20] Exhibit WWD-2, pages 18, 21. This is from FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109 "FPL Steel Scrap Price Analysis".

A. Yes. Out of the $106,426,281 Mr. Allis proposes to charge ratepayers per year for dismantlement costs, $60,563,527 is attributable to his dismantlement costs for the solar production facilities (57% of the total claimed dismantlement).[21] However, Mr. Allis' only relied upon the specific information for one FPL solar plant, the FPL Okeechobee Solar Energy Center, as will be discussed.

Q. DID MR. ALLIS PREPARE DISMANTLEMENT STUDIES FOR NUMEROUS FPL SOLAR SITES IN PREPARATION FOR HIS PROPOSED DISMANTLEMENT COSTS?

A. No. In his testimony Mr. Allis says the following:

> For solar and battery energy storage units, we developed an average cost per plant which was applied to the remaining units.[22]

Q. IN RESPONSE TO THE DISCOVERY, DID MR. ALLIS ADMIT THAT HE DID NOT AVERAGE THE COST OF MULTIPLE SOLAR UNITS?

A. Yes. Mr. Allis prepared one solar dismantlement cost estimate, which was based on the "Okeechobee Solar Dismantlement Cost Estimate." The estimate was not based on average costs. OPC's Thirteenth Set of Interrogatories, No. 342 requested the following:

> Are the 'tons of structural steel' and other amounts included in the 'Okeechobee Solar Dismantlement Cost Estimate' (which was provided in response to OPC's Second Set of Interrogatories, No. 102) the 'tons of structural steel' and other amounts **which are physically at the specific, actual FPL Okeechobee Solar Energy Center** located in Okeechobee County? (Emphasis added).

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[21] Exhibit NWA-2, pages 9-10.
[22] Witness Allis Direct Testimony, page 52, lines 20-21.

Mr. Allis answered, "Yes." [23]

For the solar plants he did not develop "an average cost per plant which was applied to the remaining units."[24] He created numbers which he admits "are physically at the specific, actual FPL Okeechobee Solar Energy Center located in Okeechobee County"[25] and assumed those numbers would apply to all FPL solar facilities of similar megawatts.

Q. HAVE YOU MADE ANY SPECIFIC ADJUSTMENTS TO THE DISMANTLEMENT ESTIMATES OF THE SOLAR PRODUCTION FACILITIES FOR THE FACT MR. ALLIS ASSUMED VIRTUALLY ALL SOLAR DISMANTLEMENT'S WOULD BE IDENTICAL TO THE OKEECHOBEE SOLAR PLANT, AND RELATED PROBLEMS?

A. No. I have not made a specific adjustment for this, but I did consider it and other issues when making my contingency recommendation, which is discussed later in this testimony.

VI. <u>MR. ALLIS UNDERSTATES THE VALUE OF SCRAP.</u>

Q. WHAT IMPACT DOES THE VALUE OF SCRAP HAVE IN THE DISMANTLEMENT STUDY?

A. Scrap is a deduction. Therefore, the lower the value of scrap estimated, the higher the dismantlement charge to ratepayers, with everything else remaining the same.

[23] Exhibit WWD-2, page 36. This is FPL's response to OPC's Thirteenth Set of Interrogatories, No. 342.
[24] Witness Allis Direct Testimony, page 52, lines 20-21.
[25] FPL's response to OPC's Thirteenth Set of Interrogatories, No. 342.

Q. WHAT DO MR. ALLIS' WORK PAPERS SHOW FOR THE PRICE FOR STAINLESS STEEL?

A. Mr. Allis shows that the market price for stainless steel scrap at the time he prepared his dismantlement study was $360 per ton.[26] Mr. Allis used a price of $350 per ton in his dismantlement study for stainless steel.[27] I am not objecting to his use of $350 per ton, which is 97% of the then-current market price of $360.

A. <u>Scrap Copper</u>

Q. FOR COPPER SCRAP, IS THE PRICE MR. ALLIS USED IN HIS DISMANTLEMENT STUDY AROUND 97% OF THE CURRENT MARKET PRICE AT THE TIME HE PREPARED HIS DISMANTLEMENT STUDY?

A. No. Mr. Allis' workpapers show that the current market price of copper scrap at the time Mr. Allis prepared his dismantlement study was $7,560 per ton.[28] However, the price he used in his dismantlement study was only $3,000 per ton.[29] The price he used in his dismantlement study is around 40% of the market price.

Q. PREVIOUSLY YOU DISCUSSED THE FACT THAT MR. ALLIS WAS DOUBLE CHARGING FOR TRANSPORTATION OF THE SCRAP. DOES THIS ISSUE GO BEYOND THE DOUBLE ~~CHECKING~~ CHARGING ISSUE?

[26] Exhibit WWD-2, page 28. This is from FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109 "FPL Stainless and Other Alloy Steel Scrap Price Analysis."
[27] Id.
[28] Exhibit WWD-2, page 22. This is from FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109 "FPL Copper Base Scrap Price Analysis."
[29] Exhibit WWD-2, page 22.

A. Yes. As demonstrated above, the price for scrap copper that Mr. Allis is using in his dismantlement study is in excess of $4,000 per ton less than the market price. As previously discussed, Mr. Allis double-charging for transportation is an issue that is in the range of around $60 per ton. There are large additional problems in Mr. Allis' scrap prices, in addition to Mr. Allis double charging for transportation of the scrap.

Q. WHAT MARKET PRICE FOR A STANDARD GRADE OF COPPER SCRAP DOES MR. ALLIS SHOW IN HIS WORKPAPER?

A. Mr. Allis shows the prices for #2 Copper Wiring and Tubing. This is copper wiring or other copper that can have paint, solder, or other coatings on it. In other words, it is not perfect. I accept this as reasonable for the typical copper from a power plant, although some of the copper scrap might be a grade with a higher price than this and some might be a grade with a lower price than this.

Q. WHAT WAS THE CURRENT PRICE FOR #2 COPPER WIRING AND TUBING THAT MR. ALLIS KNEW WHEN HE WAS PREPARING HIS DISMANTLEMENT STUDY?

A. Mr. Allis' workpapers shows he knew the "Current" price of #2 Copper Wiring and Tubing was $7,560 per ton.[30]

Q. DO YOU HAVE A MORE RECENT PRICE FOR COPPER SCRAP?

[30] Exhibit WWD-2, page 22.

A. Yes. As of May 29, 2025, the same site Mr. Allis referenced, now shows a scrap price of $4.35 per pound on the East Coast [$8,700 per ton] for #2 Copper Wiring and Tubing.[31] In my recommendation, I have not given weight to the more recent market price of $8,700 per ton, but it is useful to understand that the scrap price has not gone down since the $7,560 per ton market price Mr. Allis knew when he prepared his study.[32]

Q. WHAT PRICE FOR COPPER SCRAP DID MR. ALLIS USE IN HIS DISMANTLEMENT STUDY?

A. The price for copper scrap Mr. Allis uses in his dismantlement study is $3,000 per ton. In Mr. Allis' Dismantlement study, he states the following: [33]

> Prices used are as follows:
> - Steel - $150/ton to $160/ton
> - Stainless Steel - $350/ton
> - Aluminum - $1000/ton
> - Copper - $3000/ton.

Q. IS IT REASONABLE FOR MR. ALLIS TO USE A PRICE OF $3,000 PER TON WHEN HE KNEW THE MARKET PRICE OF COPPER SCRAP WAS $7,560 PER TON?

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[31] On the USA East Coast "The average price of #2 Copper Wire and Tubing dropped 4.4% to $4.35 per pound by the conclusion of the week." Weekly Scrap Metal Price Report- May 30, 2025 visited 6/2/2025. Weekly Scrap Metal Price Report- May 30, 2025 [For the week of May 23-29, 2025].

[32] Mr. Allis' workpapers also show the scrap price for "#2 Insulted Copper Wire 50% Recovery Scrap Price." Exhibit WWD-2, page 22. #2 Insulted Copper Wire is thin, light wire of 16 gauge or less, such as telecommunications wiring. In Martin Dismantlement Cost estimate, the only copper scrap was from generators and step up transformer. ("Units 3 &4" Line 108, 279, and 354). Mr. Allis is not showing the scrap on communications wire in this plant.

[33] Exhibit NWA-2, pages 51-52.

A. No. The price he used in his dismantlement study is around 40% of the market price.

Q. HAVE YOU MADE A SPECIFIC ADJUSTMENT FOR MR. ALLIS USING A PRICE FOR SCRAP COPPER WHICH WAS ONLY AROUND 40% OF THE MARKET PRICE?

A. No. I have not made a specific adjustment for Mr. Allis using a price for scrap copper which was only around 40% of the market price. I did consider it and other issues when making my contingency recommendation, which is discussed later in this testimony.

B. Scrap Steel

Q. YOU PREVIOUSLY DEMONSTRATED THAT FOR STAINLESS STEEL, THE $350 PRICE MR. ALLIS USED IN HIS DEPRECIATION STUDY WAS 97% OF THE THEN-CURRENT MARKET PRICE OF $360 DOLLARS. FOR STEEL SCRAP, IS THE PRICE MR. ALLIS USED IN HIS DECOMMISSIONING STUDY AROUND 97% OF THE MARKET PRICE?

A. No. For common types of steel scrap, the current market price at the time Mr. Allis prepared his dismantlement study was $315 per ton. However, the price he used in his dismantlement study was only $160 per ton,[34] which is approximately 50% of the market price.

Q. WHAT CURRENT PRICE FOR "STRUCTURAL STEEL" AND "HMS 1" OF STEEL SCRAP DID MR. ALLIS SHOW IN HIS WORKPAPER?

[34] Exhibit NWA-2, pages 51-52.

A. Mr. Allis shows the current price of $315 per ton for both "Structural Steel" and "HMS 1."[35]

Q. WHAT PRICE FOR STEEL SCRAP DID MR. ALLIS USE IN HIS DISMANTLEMENT STUDY FOR "STRUCTURAL STEEL" AND "HMS 1"?

A. The price for steel scraps Mr. Allis used in his dismantlement study for "Structural Steel" and "HMS 1" was $160 per ton (and he used $150 per ton for some lower value steel scrap).

Q. HAVE YOU MADE A SPECIFIC ADJUSTMENT TO ADJUST FOR MR. ALLIS USING A PRICE FOR SCRAP STEEL WHICH WAS ONLY AROUND 50% OF THE MARKET PRICE?

A. No. I have not made a specific adjustment for Mr. Allis using a price for scrap steel which was only around 50% of the market price for scrap steel. I did consider it and other issues when making my contingency recommendation, which is discussed later in this testimony.

C. <u>Scrap Aluminum</u>

Q. HAVE YOU PERFORMED A SIMILAR ANALYSIS OF SCRAP ALUMINUM?

A. Yes. When Mr. Allis prepared his study, the price of scrap aluminum was $1,460 per

[35] Exhibit WWD-2, page 21. FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109. The file named "FPL Steel Scrap Price Analysis." The column labeled "Current" price shows $315 for both "Structural Steel" and "HMS 1."

ton.[36] Mr. Allis uses a price of only $1,000 per ton for aluminum scrap in his dismantlement study.[37]

Q. HAVE YOU MADE A SPECIFIC ADJUSTMENT TO ADJUST FOR MR. ALLIS USING A PRICE FOR SCRAP ALUMINUM WHICH WAS ONLY AROUND 68% OF THE MARKET PRICE?

A. No. I have not made a specific adjustment for Mr. Allis using a price for scrap aluminum which was only around 68% of the market price for scrap aluminum. I did consider it and other issues when making my contingency recommendation, which is discussed later in this testimony.

VI. <u>CONTINGENCY</u>

Q. WHAT DOES MR. ALLIS SAY IS INCLUDED IN HIS "CONTINGENCY COST"?

A. Mr. Allis says:

> A contingency cost represents costs to a project that are not specifically identified but are reasonably expected to occur. Contingency accounts for uncertainty in estimates related to scope and conditions, which is a function not only of the characteristics of the facility but also the level of detail in developing the estimates.[38]

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[36] Exhibit WWD-2, page 25. This is from FPL's response to OPC's Ninth Set of Interrogatories, No. 272, which documents were provided in FPL's response to OPC's Ninth Request for Production of Documents, No. 109, "FPL Aluminum Scrap Price Analysis" (Column labeled "Current" price).
[37] Exhibit NWA-2, pages 51-52.
[38] Direct Testimony of FPL Witness Allis, page 54, lines 1-14

Q. MR. ALLIS IS ASSUMING THAT THE "UNCERTAINTY IN ESTIMATES" WILL RESULT IN A HIGHER COST THAN HE HAS OTHERWISE ASSEMBLED. IS IT POSSIBLE THAT THE "UNCERTAINTY IN ESTIMATES" COULD RESULT IN A LOWER TOTAL COST THAN WHAT MR. ALLIS HAS PRESENTED?

A. Yes. "Uncertainties" can go in either direction.

It should be noted that the dismantlement study includes all indirect costs and overheads in other charges, so the contingency cost is not for these. Mr. Allis cannot support his contingency cost as costs, but he proposes the ratepayers be charged for them anyway.

Q. ARE THERE REASONS TO EXPECT THAT THE ACTUAL DISMANTLEMENT COST, IF THE DISMANTLEMENT WAS PERFORMED BY AN EXPERIENCED DISMANTLEMENT CONTRACTOR, WOULD BE SUBSTANTIALLY LESS THAN THE NUMBERS MR. ALLIS HAS ESTIMATED?

A. Yes. It is reasonable to expect that the dismantlement, if performed by an experienced dismantlement contractor, would be substantially less than the numbers Mr. Allis has created.

1. It is reasonable to expect an experienced dismantlement contractor will capture efficiencies not known to Mr. Allis or Mr. Barry, who have never participated in the actual physical dismantlement of any production plant, as detailed earlier in my testimony.

2. Mr. Allis' dismantlement study double charges ratepayers for transportation costs. It is unreasonable to believe that a dismantlement contractor bidding for the job would be able to double charge for transportation costs.
3. Mr. Allis solar dismantlement analysis reviewed only one of the many FPL solar production facilities, specifically the FPL Okeechobee Solar Energy Center. When bidding for the contracts, it is reasonable to expect the dismantlement contractors would have to do a more detailed and thorough analysis, instead a "one-size-fits-all" analysis.
4. Mr. Allis is proposing to charge ratepayers on the assumption that the scrap copper will be sold for $3,000 per ton, when the market price of copper scrap is $7,560 per ton. It is unreasonable to expect that an experienced dismantlement contractor would sell the scrap copper at 40% of the open market price.
5. Mr. Allis is proposing to charge ratepayers on the assumption that the scrap steel will be sold for $160 per ton, when the market price of scrap steel is $315 per ton. It is unreasonable to expect that an experienced dismantlement contractor will sell the scrap steel at 50% of the open market price of scrap steel.
6. When Mr. Allis' prepared his study, the price of scrap aluminum was $1,460 per ton. Mr. Allis uses a price of only $1,000 per ton for aluminum scrap in his dismantlement study. It is unreasonable to expect that an experienced dismantlement contractor will sell the scrap aluminum at 68% of the open market price of scrap aluminum.

There are thousands of calculations and assumptions that Mr. Allis made in his dismantlement study, which cannot all be checked or verified since we have numerically limited discovery requests and a narrow time window between when the study was filed and when intervenor testimony is due. It is reasonable to assume that when we find as many obvious overcharges of ratepayers as I have proven, there are many others I have not seen.

Q. WHAT DO YOU RECOMMEND FOR THE CONTINGENCY COST?

A. The appropriate Contingency adjustment is -25% from Mr. Allis' estimates. This, and the adjustment of 6.26% for the discount rate used in the present-value calculation, are the only two adjustments I have made to the dismantlement study. With these two valid adjustments, the annual amount of $106,426,281 Mr. Allis proposes charging ratepayers for dismantlement costs,[39] becomes the corrected amount of $51,999,577. This is shown on the Exhibit WWD-5. This is the annual amount I recommend for the dismantlement costs for the FPL non-nuclear production units.

VIII. MR. ALLIS' DEPRECIATION STUDY

Q. WILL YOU PLEASE NOW ADDRESS MR. ALLIS' DEPRECIATION STUDY, EXHIBIT NWA-1, AND THE ASSOCIATED TESTIMONY AND DOCUMENTS?

A. Yes.

A. Without disclosing he had done so, Mr. Allis increased the Scherer depreciation rate by removing $77 million from its depreciation reserve.

[39] Exhibit NWA-2, page 9-10.

Q. MR. ALLIS STATES THE FOLLOWING:

> **For Scherer Unit 3, the recommended life span is 12 years shorter than the current estimate but is consistent with the life span currently used by the plant's co-owner and operator, Georgia Power.**[40]

DID MR. ALLIS DO SOMETHING ELSE THAT INCREASED HIS PROPOSED DEPRECIATION RATES FOR SCHERER UNIT 3?

A. Yes. It is correct the Scherer Unit 3 life is shorter than the prior study. However, without mentioning it in his testimony or in his depreciation study, Mr. Allis further increased the Scherer Unit 3 and Scherer Common depreciation rate by transferring $77,709,963 out of the Scherer Unit 3 and the Scherer Common depreciation reserves.[41] Removing depreciation reserve increases the depreciation rate, everything else the same.

With the "12 years shorter" life span, the Total Scherer Steam Plant (Unit 3 and Common) depreciation rate would be 5.10% overall.[42] After transferring $77,709,963 out of the Scherer Steam Plant depreciation reserve, Mr. Allis proposes an overall depreciation rate of 7.09% for the Scherer Plant. Reducing the amount in the Scherer Plant depreciation reserve increased the proposed Scherer Plant depreciation rates from 5.10%[43] to 7.09%.[44] The resulting 7.09% depreciation rate is one of the highest proposed depreciation rates for any production plant. The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

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[40] Direct Testimony of FPL witness Allis, page 26, Lines 21-23.
[41] Mr. Allis transferred $67,748,337 out of the Scherer Unit 3 reserve, and $9,961,626 out of the Scherer Common reserve. See Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[42] This is shown on Exhibit WWD-7, page 1. This is calculated using everything else the same as Mr. Allis used in his calculations but uses the books reserve.
[43] Exhibit WWD-7, page 1. This is calculated using everything else the same as Mr. Allis used (including the same life), but using the book reserve amount (not reducing the depreciation reserve by $77,709,963).
[44] Exhibit NWA-1, page 60.

Q. DOES THE SCHERER PLANT HAVE A RELATIVELY SHORT REMAINING LIFE COMPARED TO ALL PRODUCTION UNITS?

A. Yes. The Scherer Steam Plant has an average composite remaining life of 9.63 years.[45] In total, the FPL non-nuclear production plants have an average composite remaining life of over 21 years.

Q. HOW DOES TRANSFERRING MONEY OUT OF A UNIT WHICH WILL RETIRE SOON CREATE A HIGH DEPRECIATION RATE?

A. One of the goals of depreciation is to recover from ratepayers the investment and net salvage by the time the investment retires. When Mr. Allis transfers money out of the reserve of a unit which will retire in a few years, that artificially creates a deficiency. The ratepayers have only a few years to pay off the deficiency so created. That creates a higher depreciation rate.

Q. ON PAGE 49, LINES 5 THROUGH 11 OF HIS TESTIMONY, MR. ALLIS STATES:

> **The net impact of all these transfers on accumulated depreciation is zero, as they are merely transfers between depreciable groups.**
>
> **Generally, the transfers are all also within the same function of plant and, as a result, the impact on functional book reserves is also zero. Approximately $17.1 million as of December 31, 2025, is recommended to be transferred within the generation function of plant but between steam and other production functions.**

[45] Exhibit NWA-1, page 60.

DO RESERVE TRANSFERS IMPACT THE OVERALL DEPRECIATION EXPENSE?

A. Yes. Transferring money out of an account which has a relatively short remaining life can increase the total depreciation expense, even if the total accumulated depreciation (depreciation reserve) stays the same. To demonstrate this, below I show two accounts which have different remaining lives:

Figure 1:

	Original Cost	Accumulated Depreciation Reserve Per Book			Future Accrual	Remaining Life	Annual Depreciation Expense
A	B	C	D	E	F = B-C	G	H = F/G
Plant 1	$25,000	$10,000			$15,000	5	$3,000
Plant 2	$25,000	$10,000			$15,000	25	$600
Total	$50,000	$20,000			$30,000		$3,600

If $8,000 is transferred out of the depreciation reserve of the account which has the shorter remaining life, into the account with the longer remaining life, the total depreciation expense increases, even though the total depreciation reserve amount stays the same. This is shown below:

Figure 2:

	Original Cost	Accumulated Depreciation Reserve Per Book	Transfer Reserve	Adjusted Reserve	Future Accrual	Remaining Life	Annual Depreciation Expense
A	B	C	D	E=C +D	F = B-E	G	H = F/G
Plant 1	$25,000	$10,000	-$8,000	$2,000	$23,000	5	$4,600
Plant 2	$25,000	$10,000	$8,000	$18,000	$7,000	25	$280
Total	$50,000	$20,000	$0	$20,000	$30,000		$4,880

Transferring reserves out of the account with the shorter remaining life increased the total depreciation expense from $3,600 to $4,860, even though the total depreciation reserve amount stayed the same.

Q. WHAT PRODUCTION UNIT HAS THE SHORTEST COMPOSITE REMAINING LIFE?

A. Out of all the production units in the depreciation study, the Gulf Clean Energy Center Unit 4 has the shortest Composite Remaining Life at 3.93 years.[46]

Q. DID MR. ALLIS TRANSFER MONEY OUT OF THE DEPRECIATION RESERVE OF THIS UNIT THAT HAD THE SHORTEST COMPOSITE REMAINING LIFE?

A. Yes. Mr. Allis transferred $12,923,007 out of the depreciation reserve of this unit that had the shortest composite remaining life.[47]

Without Mr. Allis' proposed reserve transfer, the Gulf Clean Energy Center Unit 4 would have an overall depreciation rate of 0%.[48] This means the ratepayers had fully paid off the investment in Gulf Clean Energy Center Unit 4.[49]

After transferring money out of its depreciation reserve, Mr. Allis proposes a depreciation rate of 7.50%, which is relatively high. The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

Q. PLEASE PROVIDE AN ANALOGY TO WHAT MR. ALLIS HAS DONE.

A. You have been making your mortgage payments for decades. You have finally paid the house loan off, and you expect the bank to no longer be billing you for the mortgage.

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[46] Exhibit NWA-1, page 59. For comparison, remaining lives of all production units are on pages 59-68.
[47] See Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[48] This is shown on Exhibit WWD-7, page 1. This is calculated using everything else the same as Mr. Allis used in his calculations but uses the books reserve.
[49] Ratepayers also provided enough money to cover the interim net salvage costs.

However, the bank continues to bill you for the mortgage. The bank had transferred some of your money out of your mortgage account into another account, which pays you a lower interest rate than the interest rate you pay on the mortgage.

Q. WHAT PRODUCTION UNIT HAS THE THIRD SHORTEST COMPOSITE REMAINING LIFE?[50]

A. The Gulf Clean Energy Center Unit 5 has the third shortest Composite Remaining Life at 3.94 years.[51]

Q. DID MR. ALLIS TRANSFER MONEY OUT OF THE DEPRECIATION RESERVE OF THIS UNIT THAT HAD THE THIRD SHORTEST COMPOSITE REMAINING LIFE?

A. Yes. Mr. Allis transferred $9,155,822 out of the depreciation reserve of this unit that had the third shortest composite remaining life.[52]

Without Mr. Allis' reserve transfer, the Gulf Clean Energy Center Unit 5 would have a depreciation rate of 2.76%.[53]

After transferring money out of its depreciation reserve, Mr. Allis is proposing a depreciation rate of 7.65%, which is relatively high. The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

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[50] "Perdido LFG Units 1 and 2" has the second shortest composite remaining life. Mr. Allis did not overall transfer reserve in or out of the "Perdido LFG Units 1 and 2".
[51] Exhibit NWA-1, page 59. For comparison, the remaining lives of all production units are on pages 59-68.
[52] Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[53] This is shown on Exhibit WWD-7, page 1. This is calculated using everything else the same as Mr. Allis used in his calculations but uses the books reserve.

Q. DID MR. ALLIS TRANSFER MONEY OUT OF THE DEPRECIATION RESERVE OF THE PRODUCTION UNIT WHICH HAS THE FOURTH SHORTEST COMPOSITE REMAINING LIFE?

A. Yes. Ft. Myers GTS has the fourth shortest Composite Remaining Life at 5.33 years.[54] Mr. Allis transferred $6,098,884 out of the depreciation reserve of this unit.[55] Without Mr. Allis' proposed reserve transfer, the Ft. Myers GTS would have an overall depreciation rate of 3.81%.[56] Mr. Allis transferring money out of the depreciation reserve resulted in an overall depreciation rate of 6.19%. This is a high rate. The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

Q. DID MR. ALLIS TRANSFER MONEY OUT OF THE DEPRECIATION RESERVE OF THE PRODUCTION UNIT WHICH HAS THE FIFTH SHORTEST COMPOSITE REMAINING LIFE?

A. Yes. Lauderdale GTS has the fifth shortest Composite Remaining Life at 5.36 years.[57] Mr. Allis transferred $8,289,576 out of the depreciation reserve of this unit.[58]

Without the reserve transfer out, the Lauderdale GTS would have an overall depreciation rate of 0%.[59] This means the ratepayers had fully paid off the investment in Lauderdale GTS.[60]

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[54] Exhibit NWA-1, page 66. For comparison, remaining lives of all production units are on pages 59-68.
[55] See Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[56] This is shown on Exhibit WWD-7, page 1. This is calculated using everything else the same as Mr. Allis used in his calculations but uses the books reserve.
[57] Exhibit NWA-1 page 66. For comparison, remaining lives of all production units are on pages 59-68.
[58] See Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[59] This is shown on Exhibit WWD-7, page 1. This is calculating using everything else the same as Mr. Allis used in his calculations but uses the books reserve.
[60] Ratepayers have provided enough money to cover the interim net salvage costs.

By transferring money out of the depreciation reserve, Mr. Allis calculated an overall depreciation rate of 6.39% for the Lauderdale GTS. This is a high rate. The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

Q. DID MR. ALLIS TRANSFER MONEY OUT OF THE DEPRECIATION RESERVE OF THE PRODUCTION UNIT WHICH HAS THE SIXTH SHORTEST COMPOSITE REMAINING LIVES?

A. Yes. Scherer Steam is the production plant with the sixth shortest composite remaining life. As previously discussed, Mr. Allis transferred $77,709,963 out of the Scherer plant depreciation reserve.[61] Without Mr. Allis' reserve transfer, the Scherer Steam Plant would have an overall depreciation rate of 5.10%.[62] His reserve transfer resulted in his high proposed depreciation rate of 7.09%.[63] The average depreciation rate is 3.42% for all FPL non-nuclear production plants at current rates.

Q. PLEASE SUMMARIZE THE ABOVE ISSUE.

A. Mr. Allis transferred money out of the depreciation reserves of five out of the six production units which have the shortest composite remaining lives. By doing so he greatly increased his proposed depreciation rates for those units.

[61] See Exhibit WWD-7, page 2, which uses page 4 of Exhibit WWD-6 as its source.
[62] This is shown on Exhibit WWD-7, page 1. This is calculating using everything else the same as Mr. Allis used in his calculations but uses the books reserve.
[63] Exhibit NWA-1, page 60.

Q. IF MR. ALLIS NEEDED A SOURCE FROM WHICH TO TRANSFER RESERVE, DID IT HAVE TO BE FROM THE PRODUCTION UNITS WHICH HAD THE SHORTEST REMAINING LIVES?

A. No. There are several production units which Mr. Allis' own calculations show have reserve surpluses. This means there is more money in the depreciation reserves of these units than there should be. These include the Martin Combined Cycle for which Mr. Allis shows a reserve surplus of $88 million, the Manatee Combined Cycle for which Mr. Allis shows a reserve surplus of $55 million, the Sanford Combined Cycle for which Mr. Allis shows a reserve surplus of $38 million, the Dania Beach Energy Center, for which Mr. Allis shows a reserves surplus of $44 million, among others.[64]

Q. WHAT DOES THIS MEAN?

A. It is unreasonable to transfer over $110 million from the depreciation reserves of five of the six production units that have the shortest composite remaining lives. This is unfair to FPL's ratepayers.

Q. ARE YOU OBJECTING TO THE CONCEPT OF RESERVE TRANSFERS?

A. No. Reserve transfers can be reasonable and useful. However, the money in the depreciation reserve is the ratepayers' money. It has been accumulated from past ratepayers. The ratepayers' money in the depreciation reserve should be used in a way that benefits the ratepayers.

[64] Exhibit NWA-1, pages 82-86.

B. <u>In violation of the Rules, nowhere in Mr. Allis' depreciation study, testimony or "all workpapers" did Mr. Allis, disclose he had transferred money out of the short-lived production plant reserves.</u>

Q. DID MR. ALLIS' TESTIMONY OR DEPRECIATION STUDY STATE OR SHOW THAT HE HAD TRANSFERRED MONEY OUT OF THE SCHERER UNIT 3 AND OTHER SHORT-LIVED UNITS' RESERVES?

A. No. On pages 48 and 49 of his testimony, Mr. Allis included two paragraphs in which he made general statements indicating he had made some reserve transfers, but no specific details or supporting exhibits or workpapers were provided.[65] Which specific accounts or specific production units he had transferred reserve from or to, or the dollars amounts of any such transfers, was never disclosed anywhere in the FPL direct filing. For example, to the best of my knowledge, nowhere in the FPL direct filing is it disclosed that Mr. Allis transferred money out of the Scherer Unit 3 reserve.

Q. DID THE WORK PAPERS THAT MR. ALLIS PROVIDED WHEN ASKED TO "PLEASE PROVIDE ANY AND ALL WORKPAPERS USED TO DEVELOP ALL TESTIMONY AND EXHIBITS ATTACHED TO TESTIMONY"[66] SHOW THAT HE HAD TRANSFERRED MONEY OUT OF THE SCHERER UNIT 3 RESERVE?

A. No. The workpapers Mr. Allis provided when asked to "please provide any and all workpapers used to develop all testimony and exhibits attached to testimony" did not show that he had transferred money out of the Scherer Unit 3 reserve.

[65] The only dollar amount he provided in that discussion is as follows: "Approximately $17.1 million as of December 31, 2025, is recommended to be transferred within the generation function of plant but between steam and other production functions."
[66] Exhibit WWD-2, page 4. (OPC's First Request for Production, Request No. 15).

Only later, when the OPC and Staff specifically asked for the workpapers showing his reserve transfers, [67] did Mr. Allis provide, in response to Staff's Fourth Set of Interrogatories, No. 86, the workpapers which show his reserve transfers, including the fact that he had transferred $77,709,963 out of the Scherer Unit 3 and Scherer Common Plant reserve. Mr. Allis' reserve transfer details were first posted on the FPL discovery website on April 14, 2025, and were then, for the first time, available to those with access to that website.

Q. WHAT IS A REQUIREMENT STATED IN RULE 25-6.0436(5)(F), FLORIDA ADMINISTRATIVE CODE (F A.C.)?

A. Rule 25-6.0436(5)(f), F.A.C. includes the requirement that a depreciation study shall include:

> The explanation and justification shall discuss any proposed transfers of reserve between categories or accounts intended to correct deficient or surplus reserve balances.

Q. DID MR. ALLIS' DEPRECIATION STUDY OR TESTIMONY OR EVEN ANY WORKPAPERS PROVIDED IN RESPONSE TO THE REQUEST FOR "ALL WORKPAPERS," EXPLAIN AND JUSTIFY HIS TRANSFERRING RESERVE OUT OF SCHERER UNIT 3 AND OUT OF THE OTHER SHORT-LIVED PRODUCTION UNITS?

[67] Exhibit WWD-2, pages 11-12. (OPC's Ninth Set of Interrogatories, Interrogatory No. 266). See Page 2 of Exhibit WWD-6 (Staff's Fourth Set of Interrogatories, Interrogatory No. 86).

A. No. Mr. Allis' depreciation study, testimony, and even the "all workpapers" he provided, did not explain and justify these transfers. They did not even show that these specific transfers existed.

Q. WHAT IS ANOTHER REQUIREMENT STATED IN RULE 25-6.0436(4)(E), F.A.C.?

A. Rule 25-6.0436(4)(e), F.A.C. states that:

> (e) The possibility of corrective reserve transfers shall be investigated by the Commission prior to changing depreciation rates.

Q. DID MR. ALLIS' DEPRECIATION STUDY, TESTIMONY, OR ANY PART OF THE FPL DIRECT CASE, PROVIDE THE INFORMATION THE COMMISSION WOULD REASONABLY REQUIRE IN ORDER TO INVESTIGATE THE "RESERVE TRANSFERS" MR. ALLIS HAD INCLUDING IN HIS CALCULATION OF HIS PROPOSED DEPRECIATION RATES?

A. No. Nothing in Mr. Allis' depreciation study, direct testimony, or anything that I am aware of that FPL filed in its direct case, even disclosed that Mr. Allis had transferred reserve out of Scherer Unit 3, or out of the other short-lived production units. It is not reasonable to believe that anyone could investigate, these "reserve transfers", when FPL had not even informed the Commission of the existence of these transfers. Mr. Allis made these undisclosed transfers in calculating his proposed depreciation rates.

Q. RULE 25-6.0436(4)(E), F.A.C., STATES THAT:

> **(e) The possibility of corrective reserve transfers shall be investigated by the commission prior to changing depreciation rates.**

HAS MR. ALLIS AND THE FPL FILING PROVIDED THE INFORMATION REASONABLY NEEDED TO CONDUCT THE INVESTIGATION WHICH IS REQUIRED "PRIOR TO CHANGING DEPRECIATION RATES".

A. As a depreciation expert, I can state that Mr. Allis and the FPL filing did not provide the information reasonably needed to conduct the investigation into Mr. Allis' proposed "reserve transfers" **(**which the Rule states is required "prior to changing depreciation rates").

Worse than that, even after Mr. Allis provided his workpapers in response to the "all workpapers" request, there was still no information even showing that he had transferred money out of the Scherer 3 reserve and out of the reserves of the other short-lived units. Even after that discovery response, it had not even been disclosed that Mr. Allis had transferred money out of the Scherer 3 reserve and out of the reserves of the other short-lived production units.

In my opinion, Mr. Allis has not met the plain meaning of Commission Rules. I cannot recommend Mr. Allis' proposed "changing depreciation rates," when he has not met the requirements which must be met "prior to changing depreciation rates".

C. <u>FPL misrepresents "spares."</u>

Q. **PAGES 48-49 OF WITNESS ALLIS' TESTIMONY STATES THE FOLLOWING:**

> **Specifically, reserve transfers are recommended for most combined cycle generation facilities between capital spare parts and non-capital spare parts accounts, other fossil production sites, solar accounts, and for accounts 371 and 392.**

WHAT DOES FPL SAY THEIR TERMS "NON-CAPITAL SPARE PARTS" AND "CAPITAL SPARE PARTS" INCLUDE?

A. In response to discovery, FPL has indicated what is calling "non-capital spare parts" and "capital spare parts", includes investments which are actively in use in production units.[68] Therefore they are not "spare parts". The names Mr. Allis and FPL are using misrepresent what is in those accounts.

D. <u>Without stating he was doing so, Mr. Allis shortened the lives in certain solar production categories.</u>

Q. WHAT AVERAGE SERVICE LIFE DOES MR. ALLIS SAY HE IS USING FOR SOLAR FACILITIES?

A. Mr. Allis says he is keeping the life spans the same as they are now. For example, he states the following:

> The life span estimates for the solar facilities are 35 years. Both of these estimates are consistent with the current life spans for these facilities that were adopted in Docket No 20210015-EI.[69]

Q. DID MR. ALLIS ACTUALLY KEEP THE LIFE SPAN ESTIMATES FOR THE SOLAR PRODUCTION FACILITIES THE SAME 35 YEARS AS CURRENTLY APPROVED?

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[68] Exhibit WWD-6, page 2. This is the FPL response to Staff's Fourth Set of Interrogatories, No. 86.
[69] Exhibit NWA-1, pages 711-712.

A. No. For example, for Small Scale Solar Production Mr. Allis proposes a 25-S2.5, as shown on page 78 of his depreciation study.[70] A 25-S2.5 is a 25-year Average Service Life.

Mr. Allis shortened this solar life, which is one reason his proposed depreciation rate increases from the currently approved 3.03%, to his proposed 3.99%.

Q. FOR SPACE COAST SOLAR, DID MR. ALLIS ACTUALLY KEEP THE LIFE ESTIMATES SIMILAR TO THE CURRENTLY APPROVED?

A. No. As can be seen on page 78 of Mr. Allis' depreciation study, for Space Coast Solar the currently approved interim survivor curve is 50-R 2.5 for most of the accounts. Mr. Allis has replaced that with a 35-S2.5 interim survivor curve, which is shorter.

Q. DOES MR. ALLIS USING A 35-S2.5, INTERIM SURVIVOR CURVE MEAN THAT HE IS USING A 35-YEAR AVERAGE SERVICE LIFE?

A. Not when that is an **interim** survivor curve. When that is an **interim** survivor curve, the life is reduced by the final retirements, which are also part of the calculation. The effective life Mr. Allis uses is less than 35 years. This is one reason the current depreciation rate of 3.01% is increased to 4.26% for Space Coast Solar in Mr. Allis' proposal.

Q. FOR DISCOVERY SOLAR, DID MR. ALLIS ACTUALLY KEEP THE LIFE ESTIMATES SIMILAR TO THE CURRENTLY APPROVED?

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[70] Exhibit NWA-1, page 78.

A. No. As can be seen on page 78 of Mr. Allis' depreciation study, for Discovery Solar the currently approved interim survivor curve is 50-R 2.5 for most of the accounts. Mr. Allis has replaced that with a 35-S2.5 interim survivor curve, which is shorter.

Q. DOES MR. ALLIS USING A 35-S2.5, INTERIM SURVIVOR CURVE MEAN THAT HE IS USING A 35-YEAR AVERAGE SERVICE LIFE FOR DISCOVERY SOLAR?

A. Not when that is an **interim** survivor curve. When that is an **interim** survivor curve, the life is reduced by the final retirements, which are also part of the calculation. The effective life Mr. Allis uses is less than 35 years. This is one reason the current depreciation rate of 3.00% for Discovery Solar is increased to 3.67% in Mr. Allis' proposal.

IX. DEPRECIATION RECOMMENDATION

Q. WHAT IS YOUR RECOMMENDATION PERTAINING TO MR. ALLIS' DEPRECIATION STUDY?

A. As a depreciation expert, I can state that Mr. Allis and the FPL filing did not provide the information reasonably needed to conduct the investigation into Mr. Allis' proposed "reserve transfers" (which investigation the Rule states is required "prior to changing depreciation rates").

In my opinion, Mr. Allis has not met the plain meaning of Commission Rules. I cannot recommend Mr. Allis' proposed "changing depreciation rates", when he has not met the requirements which must be met "prior to changing depreciation rates".

Q. ARE THERE OTHER FACTORS?

A. Yes. In addition, Mr. Allis says the following:

> The life span estimates for the solar facilities are 35 years. Both of these estimates are consistent with the current life spans for these facilities that were adopted in Docket No 20210015-EI.[71]

But we have proven that is not true.

This, along with the fact that Mr. Allis removed significant depreciation reserve from the production units that have the shortest lives, raises concerns about what is going on in Mr. Allis' depreciation study that we are not aware of. Mr. Allis' depreciation study contains tens of thousands of numbers created by Mr. Allis, as can be seen on pages 59 through 678 of his Exhibit NWA-1. It is impossible to obtain through discovery, examine in detail, and correct all the adjustments and assumptions Mr. Allis made in producing those tens of thousands of numbers. We have only a limited time and a limited number of allowed discovery requests. I cannot reasonably base the appropriate depreciation rates charged to ratepayers on a depreciation study which substantially relies upon assumptions, projections and/or estimates prepared on behalf of the utility by a witness that transferring money out of the depreciation reserve of five out of the six production units that have the shortest remaining lives, and only disclosed that was done in an April 14, 2025, discovery response which was provided over six weeks after the February 28, 2025 filing of the FPL direct case.

In my opinion, Mr. Allis' 2025 depreciation study cannot be trusted as the sole basis for raising the depreciation rates charged to ratepayers by over $170 million per year.

[71] Exhibit NWA-1, pages 711-712.

Q. WHAT DO YOU RECOMMEND?

A. The record demonstrates that the retirement dates for certain production units have changed, which should change some depreciation rates. I will make those appropriate changes in the section below. For most accounts, I recommend the use of the depreciation rates which the Commission has already found to be appropriate.

Q. DOES CONTINUING TO USE THE CURRENTLY APPROVED DEPRECIATION RATES MEAN THAT THE DEPRECIATION EXPENSE WILL BE THE SAME AS APPROVED IN THE PRIOR CASE?

A. No. At the same depreciation rate, the depreciation expense grows as the investment grows. For example, in the 2021 case, the Original Cost as of December 31, 2021, in Account 368.00, Line Transformers was $3,493,242,494.[72] At the currently approved depreciation rate of 2.87%[73] that is an annual depreciation expense of $100,256,060 at the Original Cost as of December 31, 2021.

In this current case, the Original Cost as of December 31, 2025, in Account 368.00, Line Transformers is $ 4,679,111,700.[74] At the same currently approved depreciation rate of 2.87%[75] that is an annual depreciation expense of $134,290,506 at the Original Cost as of December 31, 2025. At the same depreciation rate, the annual depreciation expense is $34,034,446 higher.

[72] Docket No. 20210015-EI, 2021 Depreciation Study, Exhibit NWA-1, page 101.
[73] Exhibit NWA-1, page 79 (current case).
[74] Exhibit NWA-1, page 79 (current case).
[75] Exhibit NWA-1, page 79 (current case).

Q. DOES CONTINUING TO USE THE CURRENTLY APPROVED DEPRECIATION RATES MEAN THAT THE DEPRECIATION EXPENSE WILL NOT GROW OVER TIME ALONG WITH THE GROWTH OF THE INVESTMENT IN AN ACCOUNT?

A. No. Each year, the Company applies the approved depreciation rate to the then-current investment amount.[76] Because of this, the depreciation expense grows in the same proportion as the investment amount grows. For example, if in the future the Original Cost in Account 368.00, Line Transformers will have grown to $6,000,000,000 then at the currently approved depreciation rate of 2.87%, the depreciation expense will also grow to $172,200,000.

At a given depreciation rate, the depreciation expense grows in the same proportion as the investment amount grows.

Q. DOES THE RECORD SHOW THAT SOME PRODUCTION UNITS EXPECTED RETIREMENT DATES HAVE CHANGED SINCE THE CURRENTLY APPROVED DEPRECIATION RATES WERE ESTABLISHED?

A. Yes. Mr. Allis states the following:

> The dates for Scherer and GCEC Units 4 and 5 have been updated from the existing estimates based on the current outlook for each facility, which have changed from the previous depreciation study.[77]

I accept the changes in the expected retirement dates for these units and have included in my recommendations the depreciation rates which incorporate these revised

[76] This calculation is often done monthly.
[77] Witness Allis direct testimony, page 26, lines 11-13.

retirement dates. I calculated these depreciation rates using the book depreciation reserves, not the adjusted reserves Mr. Allis created by his reserve transfers.[78]

In addition, Mr. Allis has proposed a restructuring of certain Solar Production Plant accounts, which restructuring does not significantly alter the depreciation rates.[79]

I recommend the continuance of the current Commission-approved depreciation rates for all accounts, except for the depreciation rates for Scherer and Gulf Clean Energy Center (GCEC) Units 4 and 5 that should be adjusted for the different retirement dates and the Solar Production Plant restructuring.

X. CONCLUSION

Q. WHAT DO YOU RECOMMEND?

A. For the reasons discussed in this testimony, I recommend the OPC depreciation rates shown on Exhibit WWD-8.

In addition, for the reasons discussed in this testimony, I recommend the OPC Dismantlement Annual Accrual shown on Exhibit WWD-5.

Q. PLEASE COMPARE YOUR DISMANTLEMENT ANNUAL ACCRUAL RECOMMENDATIONS TO MR. ALLIS' DISMANTLEMENT ANNUAL ACCRUAL RECOMMENDATIONS.

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[78] See Exhibit WWD-7.

[79] On page 29 of his testimony, Mr. Allis discusses using a 35-year Average Service Life by utilizing a 35-S2.5 without a specific final retirement date. That produces an overall Solar Production Plant depreciation rate near 3.0% for the Solar Production Plant category, which is similar to the currently approved overall Solar Production Plant depreciation rate, which is near 3.0%. See page 78 of Exhibit NWA-1. I do not object to this structural change and have incorporated it into my proposed depreciation rates (using un-transferred book reserve). See Exhibit WWD-7.

A. The detailed differences between our proposed Dismantlement Annual Accrual can be seen on Exhibit WWD-5. The following table compares the annual dollar impact of these recommendations.

Figure 3:

FLORIDA POWER & LIGHT COMPANY
2026 AND 2027 DISMANTLEMENT ACCRUAL SUMMARY

Base/Clause	FPL Proposed Annual Accrual Effective 1/1/2026	OPC Proposed Annual Accrual Effective 1/1/2026	Difference From FPL Proposed Annual Amount
Total in Base Rate Dismantlement Accrual	$ 96,201,228	$ 41,869,736	$ (54,331,492)
Total in Clause Dismantlement Accrual	10,225,053	10,129,841	(95,213)
Total Dismantlement Accrual	**$ 106,426,282**	**$ 51,999,577**	**$ (54,426,705)**

Q. PLEASE COMPARE YOUR DEPRECIATION RATE RECOMMENDATIONS TO MR. ALLIS' DEPRECIATION RATE RECOMMENDATIONS.

A. The detailed differences between our proposed depreciation rates can be seen on Exhibit WWD-8. The following table compares annual dollar impact of these recommendations by category.

Figure 4:

COMPARISON OF THE ANNUAL ACCRUAL (DEPRECIATION EXPENSE) FOR CURRENT DEPRECIATION RATES COMPARED TO THE FPL AND OPC PROPOSED DEPRECIATION RATES						
	Current	Company Proposed		OPC Proposed		
	Depreciation Annual Amount	Depreciation Annual Amount	Increase From Current	Depreciation Annual Amount	Increase From Company	Increase From Current
STEAM PRODUCTION	58,319,229	83,434,548	25,115,319	62,164,657	(21,269,891)	3,845,428
NUCLEAR PLANT	220,324,940	235,868,370	15,543,430	220,324,938	(15,543,432)	(0)
COMBINED CYCLE	556,633,290	569,935,757	13,302,467	556,633,287	(13,302,470)	(0)
PEAKER PLANTS	41,280,802	37,277,091	(4,003,711)	41,280,798	4,003,707	0
SOLAR PRODUCTION	299,163,762	300,514,391	1,350,629	300,205,737	(308,654)	1,041,975
ENERGY STORAGE	48,894,184	49,273,466	48,894,183	48,894,183	(379,283)	0
TRANSMISSION	308,731,741	311,542,469	2,810,728	308,731,742	(2,810,727)	(0)
DISTRIBUTION	880,143,019	999,757,799	119,614,780	880,143,019	(119,614,780)	0
GENERAL PLANT	57,054,595	53,579,307	(3,475,288)	57,054,596	3,475,289	0
TOTAL DEPRECIABLE	2,470,545,562	2,641,183,198	219,152,537	2,475,432,957	(165,750,241)	4,887,403

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

ERRATA SHEET

WITNESS: William Dunkel

The following table contains the corrected errata in his direct testimony.

Page	Line	**Original**	**Revised**
12	16	$74,179,884	$74,148,833
12	17	$32,246,398	$32,277,449
26	11	$51,999,577	$52,326,838
47	Figure 3	OPC Proposed Annual Accrual Effective 1/1/2026 $41,869,736 $51,999,577	OPC Proposed Annual Accrual Effective 1/1/2026 $42,196,998 $52,326,838
47	Figure 3	Difference From FPL Proposed Annual Amount $54,331,492 $54,426,705	Difference From FPL Proposed Annual Amount $54,004,231 $54,099,433

C21-3118a

BY MR. WATROUS:

Q Mr. Dunkel, did your prefiled testimony in this docket also contain eight exhibits, labeled WWD-1 through WWD-8?

A Yes.

MR. WATROUS: And for the record, I believe these exhibits have been identified on the CEL as Exhibits 163 through 170.

BY MR. WATROUS:

Q Mr. Dunkel, do you have any corrections to make to your exhibits today?

A Not to the exhibits, no. Other than what was included in the prefiled errata.

Q Thank you.

And have you prepared a summary of your testimony?

A Yes.

Q Please provide that summary.

A Yes.

I provide depreciation expert testimony and dismantlement testimony all over the country. In many cases, I testify on behalf of the Commission or the Commission staff, or, in some cases, on behalf of the public advocate.

Mr. Allis is not a dismantlement expert. He is a depreciation expert, but not a dismantlement expert. The company has filed $106 million annual cost-based upon Mr. Allis' estimates of how many labor hours it will take to disassemble certain parts of the plants, or every part of the plant. He has never participated in a case or a project in which a plant was actually being disassembled. His firm has never been in a case in which a production plant was actually being disassembled, so how he knows how many labor hours it will take to do each step of the disassembly is beyond me. He simply does not have that experience, and that's $106 million cost.

Another thing is his study is only for the purposes of collecting money from the ratepayers. Once the company actually decides to go ahead and dismantle the plant, they will hire an experienced dismantlement contractor, and that contractor will decide how to disassemble a plant, what steps to take, how long it will take. What Mr. Allis has assumed here will have nothing do with how the plant actually gets disassembled. The experienced contractor will decide that. So this is just a cost collection process.

Mr. Allis over -- or understated the value of scrap, to understand this, the more money the company can collect from the scrap materials, the less they have to collect from the ratepayers. His own workpapers show structural steel has a scrap value of $3 -- $315 per ton. In his study, he assumed structural scrap steel has a value of $160 per ton, about half of the real open market value of scrap steel. And again, this overcharges ratepayers, because he is underestimating how much money the company will get, or the company's contractor will get from the scrap dealers. He did the same thing on other types of scrap as well.

He also double charged ratepayers for transportation of the scrap. When he was asked why he was only crediting $160 as a value of scrap for structural steel when the real price was 315 a ton, he said, quote, "this was," quote, "to account for transportation, contamination and other factors." So he is charging for transportation, but his same cost study has a different line item that charges the ratepayers for transportation of the scrap from the site to the dealer of $59.24 per ton. So he cut the price to transportation, but has another line item that's also charging for transportation. Double charge.

For these issues, I made one adjustment. The contingency is called the adjustment for, quote, "uncertainty in estimates." Since Mr. Allis doesn't even know how long it will take to do this, that's an uncertainty. I know he underrated the value of scrap. I considered that. He double charged for transportation. Considering all that, I recommend a contingency adjustment of negative 25 percent.

There is one other issue in the dismantlement study. Part of the dismantlement study is a present value calculation. Present value is defined as the discount rate that would be foregone, it's a foregone rate of return.

Now, in a demolition, the company collects money from ratepayers now, the actual dismantlement might happen 30 years from now, but the ratepayers' money has been collected 30 years in advance. So we are really talking about the value of the ratepayers' money. The rate of return, cost of money for the ratepayers' money. The company used an inflation rate of 3.6 percent instead of a rate of return. I used 6.26 as the discount rate, which is the rate of return as provided by the OPC's witness.

Okay. Moving to the depreciation study. The rule says that reserve transfers shall be investigated by the Commission prior to changing depreciation rates. That's one of the rules. But Mr. Allis, in his study, did not file the information that allows you to do that. He did not file the dollar amounts that he had transferred. The reserve transferred are nowhere in his directs testimony, nowhere in his depreciation study, nowhere even in his workpapers. OPC asked a question, provide all your workpapers. He still didn't provide that. Only later in the case, when the OPC and the staff did follow-up, we still haven't seen --

MR. BURNETT: Mr. Chairman, I am sorry, I would this witness is over five minutes a bit.

CHAIRMAN LA ROSA: No, I got it.

Mr. Dunkel, could we bring in your summary for a landing?

THE WITNESS: Sure.

In conclusion, I recommend increasing depreciation rates, which would increase the depreciated expense by five million per year, in addition to increasing the depreciation expense for the growth and investment.

On the dismantlement study, I recommend the negative 25 percent contingency factor, and a 6.2 six percent at this count rate.

MR. WATROUS: Thank you.

And at this time the OPC tenders Mr. Dunkel for cross-examination.

CHAIRMAN LA ROSA: Great. Thank you.

FEL?

MS. McMANAMON: No questions.
CHAIRMAN LA ROSA: FAIR?
MR. SCHEF WRIGHT: No questions, Mr. Chairman. Thank you.
CHAIRMAN LA ROSA: FEIA?
MR. MAY: No questions.
CHAIRMAN LA ROSA: Walmart?
MS. EATON: No questions.
CHAIRMAN LA ROSA: FRF?
MR. BREW: No questions.
CHAIRMAN LA ROSA: FIPUG?
MR. MOYLE: No questions.
CHAIRMAN LA ROSA: FPL?
MR. BURNETT: No questions.
CHAIRMAN LA ROSA: Staff?
MR. STILLER: No questions.
CHAIRMAN LA ROSA: Commissioners, any questions?
I actually have a quick question. The scrap steel, I am going to call it the industry, how volatile are the prices when you are comparing prices of what was used on a per ton basis between yourself and another witness, how -- in your opinion, how volatile would prices be over time?
THE WITNESS: They do vary, but, in fact, the

information we have is prices are actually now higher than they were in the data that he looked at and I looked at. I have not adjusted for that, but in anything, they are going up.

CHAIRMAN LA ROSA: Excellent. Thank you.

OPC, back for you to redirect.

MR. WATROUS: I do not have any redirect. Thank you, Mr. Chair.

And OPC asks that Mr. Dunkel's previously identified Exhibits No. 163 through 170 now be entered into the record.

CHAIRMAN LA ROSA: All right. Assuming no objection, so moved.

MR. WATROUS: Thank you, Mr. Chair.

(Whereupon, Exhibit Nos. 163-170 were received into evidence.)

CHAIRMAN LA ROSA: Mr. Dunkel, thank you very much. You may be excused.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: I am assuming nothing else needs to be moved into the record for that witness? Okay. Excellent.

Let's -- I will move it back to OPC. You may introduce your next witness when you are ready.

MS. CHRISTENSEN: OPC would all Mr. Dan Lawton to the stand.

CHAIRMAN LA ROSA: Thank you.

Mr. Lawton, when you are ready, if you don't mind standing and raising your right hand?

Whereupon,

DANIEL J. LAWTON

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: Yes, I do.

CHAIRMAN LA ROSA: Excellent. Great. Thank you. Feel free to get settled in.

Ms. Christensen, you -- the witness is yours when you are ready.

MS. CHRISTENSEN: Certainly.

EXAMINATION

BY MS. CHRISTENSEN:

Q Mr. Lawton, can you give your full name and business address for the record, please?

A Sure. My name is Daniel Lawton, L-A-W-T-O-N. My business address is 12600 Hill Country Boulevard, Austin, Texas.

Q And did you cause to be prefiled direct testimony in this docket on June 9th, 2025?

A I did.

Q And do you have any corrections to your prefiled testimony?

A No, other than we prefiled -- or filed with the papers in this cause an errata that made some changes to the testimony.

Q Okay. Other than the corrections that were prefiled in the errata, do you have any additional corrections today?

A Not to my knowledge.

Q Okay. And if I were to ask you the same questions contained in your prefiled testimony, would your answers be the same, including the corrections in your errata?

A They would, indeed.

MS. CHRISTENSEN: Mr. Chair, I would ask that Mr. Lawton's testimony, along with his errata, be entered into the record as though read.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of Daniel J. Lawton was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida Power & Light Company.

Docket No. 20250011-EI

Filed: June 9, 2025

DIRECT TESTIMONY

OF

DANIEL J. LAWTON

ON BEHALF

OF

THE CITIZENS OF THE STATE OF FLORIDA

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DIRECT TESTIMONY

OF

DANIEL J. LAWTON

On Behalf of the Office of Public Counsel

before the

Florida Public Service Commission

DOCKET NO: 20250011-EI

I. INTRODUCTION/BACKGROUND/SUMMARY/FINDINGS

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel J. Lawton. My business address is 12600 Hill Country Boulevard, Suite R-275, Austin, Texas 78738.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A. I have been working in the utility consulting business as an economist since 1983. My consulting engagements have included electric utility load and revenue forecasting, cost of capital analyses, financial analyses, revenue requirements/cost of service reviews, and rate design analyses in litigated rate proceedings before federal, state and local regulatory authorities, and in court proceedings. I have worked with numerous municipal utilities developing electric rate cost of service studies for reviewing and setting rates. In addition, I have a law practice based in Austin, Texas. My main areas of legal practice include administrative law representing municipalities in electric and gas utility rate proceedings and other litigation including appellate, and contract matters. I have included a brief description of my relevant educational background and professional work experience in Exhibit (DJL-1) attached to this testimony.

Q. HAVE YOU PREVIOUSLY FILED TESTIMONY IN RATE PROCEEDINGS?

A. Yes. A list of cases where I have previously filed testimony is also included in Exhibit (DJL-1).

Q. ON WHOSE BEHALF ARE YOU FILING TESTIMONY IN THIS PROCEEDING?

A. I have been retained to review the Florida Power & Light Company ("Company" or "FPL") cost of capital request, and related financial issues, on behalf of the Florida Office of Public Counsel ("OPC").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony in this proceeding is to address the Company's requested overall cost of capital for FPL's regulated electric operations. I will address and separately estimate the Company's: (i) requested overall rate of return to be earned on rate base investment; (ii) proposed capital structure; (iii) financial risk; (iv) business risk; (v) cost rates for equity capital; (vi) cost rates for investment tax credits; and (vi) long-term debt. As discussed below, the Company's filing includes cost of service estimates based on what is described as a four-year Rate Plan covering the rate years 2026, 2027, 2028, and 2029 with base rate increases in the forecasted test years of calendar years 2026 and 2027. With the understanding that OPC strongly opposes approval of the proposed four-year rate plan as addressed further by other OPC expert witnesses, my analysis addresses cost of capital in each of the proposed rate years of the multi-year rate proposal.

The Company's proposed capital costs are presented and discussed in the direct testimony of FPL cost of capital witness, Mr. James Coyne, and FPL financial witness Mr. Scott Bores, and the results presented in the Company's filed MFR Section D "Cost of Capital Schedules." In addition, I address several issues related to the Company's financial integrity, investment requirements, cash flow issues, and impacts of the proposed multi-year rate plan related to return on invested capital.

Q. WHAT MATERIALS DID YOU REVIEW AND RELY ON FOR THIS TESTIMONY?

A. I have reviewed prior orders of the Florida Public Service Commission ("Commission"), the Company's direct testimony presented in this proceeding, Company responses to discovery requests in this proceeding, Value Line Investment Survey ("Value Line"), financial reports such as the 10-K filed with the Securities and Exchange Commission ("SEC") of the Company and other utility companies of comparable risk, and other relevant financial information available in the public domain. When relying on various sources, I have referenced such sources in my testimony and attached exhibits and included copies or summaries in my Exhibits and work papers as applicable.

Q. BEFORE PROVIDING A BRIEF SUMMARY OF YOUR FINDINGS AND RECOMMENDATIONS, PLEASE PROVIDE A BRIEF OVERVIEW OF THE FPL COST OF CAPITAL REQUEST.

A. After review and analysis of the Company's cost of capital request in this case, I have reached one major overall conclusion; FPL's shareholder profit request is a substantial overreach resulting in excessive rates and harms all Florida customers if such request is granted by this Commission. As I will demonstrate later in this testimony, the Company's own numbers in the filed MFR's, testimony, and witness exhibits together demonstrate the excesses of the cost of capital request. Company cost of capital witness James Coyne relied on extreme and unreliable CAPM model results that has led to increasing the FPL shareholder profit request from the current 10.8% midpoint by 110-basis to 11.90%. Such a profit increase leads to increasing the first year of the rate plan revenue requirement by more than $550 million or about one third of the entire $1,544,780,000 proposed first year increase.[1] I will be addressing this matter when I address Mr. Coyne's Direct Testimony at Section X of this testimony.

Another way to evaluate the impact of FPL's shareholder profit request in this case, is to calculate the percentage amount of profit and associated federal income taxes that are included in customer (non-fuel) base rates. I discuss this issue in detail in Section II below. FPL's own numbers and the evidence in this case demonstrates that 49.6% of all base rates goes to pay shareholder profit and associated federal income taxes. In other words, about 50 cents of every consumer dollar paid for base rate tariff electric service goes for shareholder return and associated federal income taxes.

As I discuss below, the percentage of FPL's profit in base rates has been substantially increasing over time due to mostly inefficient financing of capital expansion by employing more costly equity rather than lower cost debt and this Commission should evaluate the disturbing trend. Moreover, I discuss in Section II how this issue is a problem that should be addressed.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS RELATED TO EQUITY RETURN IN THIS CASE.

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[1] The calculation of the 110-basis point increase in return of about $550 million is provided in Exhibit (DJL-13).

A. My analysis of the Company's requested 11.90% cost of equity capital, or shareholder profit, in this proceeding is based on evaluating capital market data employing several commonly employed financial models. The models are described in the following pages as well as summarized in the attached Exhibits (DJL-8), (DJL-9), (DJL-10), and (DJL-11). My results from these models using current financial market data employing the Company's proposed peer risk group of electric companies are summarized in the following table: [2]

Table 1
Cost of Equity Estimates Employing FPL Comparable Risk Group[3]

MODEL	RANGE LOW - HIGH	MIDPOINT	Summary averages of midpoints
DCF Model (Average Growth)	9.62% - 9.95%	9.79%	
DCF Model (Sustainable Growth)	8.51% - 8.95%	8.73%	
Two-stage DCF	9.46% - 9.87%	9.66%	3 – DCF Models 9.4%
CAPM	9.70% - 9.70%	9.70%	
ECAPM	9.89% - 9.89%	9.89%	CAPM & ECAPM 9.8%
Risk Premium	10.39% - 10.64%	10.52%	
Average of all Models (Rounded) Average of all models (excluding risk premium)	9.60% - 9.83% 9.44% - 9.67%	9.72% 9.55%	9.7% 9.6%
Minimum Maximum		8.51% 10.39%	
Reasonable Range	9.40% - 9.80%	9.60%	9.60%
Financial Risk adjustment[4]		-.40%	-.40%
Recommended equity return		9.20%	9.20%

[2] Discounted Cash Flow models ("DCF"), Capital Asset Pricing Model ("CAPM"), Empirical Capital Asset Pricing Model ("ECAPM") and Risk Premium Model.
[3] Each cost of equity capital estimate is discussed in the testimony and is presented in Exhibits (DJL-8), (DJL-9), (DJL-10), (DJL-11), and (DJL-13).
[4] The 40-basis point downward risk adjustment can be found in Section IX "Capital Structure".

The results of the cost of capital analyses shown in Tables 1 fall in a range of about 9.40% to 9.80% with a 9.60% midpoint. This 9.4% - 9.8% range includes the average of all models and the average of the models which excluded the risk premium models. Given the above, the indicated cost of capital range is 9.40 - 9.80% and a midpoint estimate cost of capital is 9.60%. However, I adjusted the midpoint downward by 40-basis points to reflect FPL's 59.60% equity ratio and lower financial risk relative to the comparable companies.

Q. WHAT IS YOUR OVERALL COST OF CAPITAL RECOMMENDATION FOR FPL IN THIS CASE?

A. Based on my analyses (which are fully explained in the following pages), I make the following conclusions and recommendations for FPL's cost of capital in each of the two test-years of the proposed multi-year rate plan:[5]

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[5] I have been made aware by counsel for the office that the OPC has taken various legal positions regarding the power or authority of the Commission to entertain the remote second fully projected test year. I am also aware that the OPC successfully challenge the authority of the Commission to determine a multi-year "rate plan" for a regulated utility in a litigated rate case that is not resolved via a settlement agreement in the form of a contract. (PSC Order No. PSC-2023-0177-FOF-GU, Docket No. 20220069-GU, p. 6, *In re: Petition for rate increase by Florida City Gas.)* My testimony, to the extent it opines on costs applicable to 2026 and 2027, does not concede the validity or legality of those years. Furthermore, although I am an attorney, I do not offer any opinion on Florida law as it relates to any of the matters in this case. I solely address the risk considerations associated with a so-called multi-year plan.

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Table 2

Recommended Capital Structure and Cost Rates for FPL Operations Rate Year 2026[6]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.07%	9.20%	4.61%
LONG-TERM DEBT	32.65%	4.64%	1.51%
SHORT-TERM DEBT	1.30%	3.80%	0.05%
CUSTOMER DEPOSITS	0.82%	2.15%	0.02%
DEFERRED INCOME TAXES	10.96%	0.00%	0.00%
FAS 109 DEFERRED TAXES	3.20%	0.00%	0.00%
INVESTMENT TAX CREDITS	1.00%	7.40%	0.07%
TOTAL CAPITAL	100.00%		6.26%

Table 3

Recommended Capital Structure and Cost Rates for FPL Operations Rate Year 2027[7]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.12%	9.20%	4.61%
LONG-TERM DEBT	32.55%	4.69%	1.53%
SHORT-TERM DEBT	1.42%	3.279%	0.05%
CUSTOMER DEPOSITS	0.81%	2.15%	0.02%
DEFERRED INCOME TAXES	11.21%	0.00%	0.00%
FAS 109 DEFERRED TAXES	2.99%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.90%	7.42%	0.08%
TOTAL CAPITAL	100.00%		6.29%

[6] Capital structure and cost rates (except equity cost and ITC cost) per Company filing MFR D-1a, 2026 test year page 1 of 1. Equity cost of 9.20% per this testimony and ITC cost based on the adjusted composite long-term debt and equity cost.

[7] Capital structure and cost rates (except equity cost and ITC cost) per Company filing MFR D-1a, 2027 test year page 1 of 1. Equity cost of 9.20% per this testimony and ITC costs per the adjusted composite of long-term debt and equity.

As discussed below, these recommended return levels (9.20% equity return in each year of the proposed rate years) are reasonable. These proposed changes to the Company's rate request result in an overall cost of capital of 6.26% for rate year 2026 and, 6.29% for rate year 2027. Again, other OPC witnesses address the issue of a second forecasted test year and the merits of the proposed four-year rate plan. I include the 2027 capital structure and cost rates for a complete record on capital cost. These alternative capital costs are consistent with current market capital costs in the utility industry, consistent with recent regulatory authority decisions around the country, and consistent with just and reasonable rates for consumers.

My analysis of the Company's overall cost of capital request, which includes: (i) a multi-year rate plan with two separate years of overall capital costs; (ii) substantially increased equity capital and long-term debt capital to fund investment over the four- year rate plan; (iii) Mr. Coyne's overstated recommended 11.90% equity return for FPL electric operations; and (iv) the overall weighted return request to be earned on rate base investment of 7.63% in 2026 and 7.64% in 2027, (see Company MFR Schedule D-1a for 2026 and 2027 test years, respectively) - indicates that the Company's request is overstated, inconsistent with current and expected market capital costs, and inconsistent with just and reasonable rates for consumers.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS IN THIS CASE.

A. Based on my analyses (which are fully explained in the following pages), I make the following conclusions and recommendations:

(i) I recommend a return of 9.20% for shareholder equity for FPL, which is consistent with current market capital cost requirements for electric utility operations and is more than adequate for FPL to maintain its financial integrity and creditworthiness;

(ii) I recommend no changes to FPL's proposed capital structure, which consists of 59.6% equity on a financial basis for each year of the multi-year rate plan. The equity ratio is well above the current 52% average equity ratios of operating electric utilities around the country, so I have adjusted the FPL equity return downward by 40-basis points due to the lower financial risk given the 59.60% equity level;

(iii) I recommend no changes to FPL's long-term or short-term debt costs, but I do adjust investment tax credit costs in capital structure to reflect my proposed composite cost of equity and long-term debt capital; and

(iv) I recommend an overall cost of capital applied to rate base investment of 6.26% for rate year 2026 and 6.29% for rate year 2027 and forward.

II. OVERVIEW OF THE COMPANY'S RATE REQUEST AND ISSUE SUMMARY

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED RATE REQUEST.

A. The Company is proposing a four-year forecasted rate plan (calendar-years 2026, 2027, 2028, and 2029)[8] which requires two substantial base rate increases and other elements authorizing added income for the Company.[9] The Company's current rates are based on a multi-year rate plan (calendar years 2022, 2023, 2024, and 2025),[10] established through a Commission-approved negotiated settlement agreement. Under the proposed multi-year rate plan, the Company's case is based on two projected test periods with substantial base rate increases for the calendar years 2026 and 2027.[11] The total amount of capital investment (rate base) for each of the first two-years of the Proposed Rate Plan is

[8] The term "rate year" is used to define the period proposed rates from this case will be in effect.
[9] Direct Testimony Scott Bores at page 54, lines 16 - 23.
[10] See PSC-2021-0202-AS-EI ("2021 Settlement").
[11] Direct Testimony Scott Bores at page 54, lines 16 - 23.

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$75,829,876,000 in 2026, and $80,751,580,000 in 2027. [12] The Company is requesting rate increases of $1,545 billion in 2026,[13] and an additional $0.927 billion in 2027.[14] Thus, the total base rate increase to customers in the first two years is $2.472 billion. The Company's four-year Rate Plan contains two added components: i) Tax Adjustment Mechanism ("TAM") covering all years of the Rate Plan, and ii) the investment tax credit ("ITC") component of the 2028 - 2029 Solar and Battery Base Rate Adjustment.[15] Other OPC witnesses address the impacts and risks of the proposed TAM and ITC component of the rate plan.

Q. PLEASE DESCRIBE THE COST DRIVERS THAT THE COMPANY ASSERTS CREATE THE NEED FOR THE PROPOSED RATE REQUEST.

A. The Company through the testimony of witness Ms. Ina Laney sets forth 11 claimed cost drivers since the last 2023 test year used for setting current rates.[16] These claimed cost drivers are presented to justify the 2026 rate increase include the following:

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[12] See MFR A-1, Projected Test Year Ended 12/31/2026 and MFR A-1, Projected Test Year Ended 12/31/2027 at page 1.
[13] See MFR A-1, Projected Test Year Ended 12/31/2026 page 1.
[14] See MFR A-1, Projected Test Year Ended 12/31/2027 page 1.
[15] Direct Testimony Ina Laney at page 5, lines 13 - 16.
[16] Direct Testimony Ina Laney at pages 26 - 38.

TABLE 4[17]
COMPANY CLAIMED COST DRIVERS FOR RATE REQUEST

Capital Initiatives	$1,839 Million
Loss of Reserve Amortization	$336 Million
Change in Weighted Cost of Capital	$256 Million
Unprotected Excess ADIT Amortization	$167 Million
Inflation and Customer Growth	$134 Million
Depreciation Costs	$122 Million
Dismantlement Costs	$56 Million
Cost offsets (IRA Tax Credits, Revenue Growth, O&M costs)	-$1,390 Million
Other	$24 Million
Total	$1,545 Million

FPL witness Laney describes the elements outlined in Table 4 above as the drivers of the need and claimed cost justification for the first year rate increase.

Q. DO YOU AGREE WITH FPL WITNESS LANEY'S VIEW OF COST DRIVERS SUPPORTING FPL'S RATE INCREASE REQUEST?

A. No, I do not. While Ms. Laney's analysis of various cost increase and decrease elements adds up to the $1.545 billion first year rate request, Ms. Laney's analysis misses entirely the true cost driver in this proceeding – shareholder profit. The Company's requested shareholder profit in this case is an astounding 11.90%. This 11.90% profit level request is combined with a 59.6% equity ratio to finance rate base capital. To put this 11.90% shareholder profit in perspective, Table 5 below demonstrates the Company profit request

[17] Direct Testimony Ina Laney at page 27, lines 1 - 13.

amounts to about 50 cents of every dollar of base rate (non-fuel) revenue requirement going to shareholder profit and the associated federal income taxes. In other words, for every dollar paid by consumers in base rates, about 50 cents would go to shareholders and related federal income taxes, if approved.

TABLE 5
(000's)
TOTAL REVENUE REQUIREMENT AND PROFITS

1	**Total Base Current Operating Revenues**	**$9,884,769**[18]
2	**Requested Rate Increase**	**$1,544,780**[19]
3	**Total 2026 Revenue (non-fuel)**	**$11,429,549**[20]
4	**Total Rate Base Request**	**$75,129,676**[21]
5	**Weighted Equity Cost @ 11.90% ROE**	**5.96%**[22]
6	**Requested Shareholder Profit**	**$4,477,729**[23]
7	**Federal Income Tax Gross-up**	**1.265823**[24]
8	**Total Profit and FIT**	**$5,668,011**[25]
	Profit and FIT as a Percent of Base Revenues	**49.59%**[26]

As shown in Table 5 above, nearly half of every dollar paid by FPL customers in base rates would be driven by the requested shareholder profit request and associated federal income taxes.

[18] See MFR C-1 Test Year 12/31/2026, line 5, column 10.
[19] See MFR A-1 Test Year 12/31/2026, line 8, column 3.
[20] Sum of lines 1 and 2.
[21] See MFR A-1 Test Year 12/31/2026, line 1, column 3.
[22] See MFR D-1a Test Year 12/31/2026, line 8, columns 10 and 11.
[23] Line 4 * line 5.
[24] Calculated as 1/(1-Corporate Tax Rate) or 1/(1-21%).
[25] Line 6 * line 7.
[26] Line 7/line 3.

As shown in Table 6 below, FPL's profit request is part of a disturbing trend that can be identified in the Company's rate filings where increased profit levels amount to a higher and higher component of base rates.

TABLE 6
FPL HISTORICAL TOTAL REVENUE REQUIREMENT AND PROFITS
($000's)

Line	DESCRIPTION	DOCKET NO. 20210015-EI	DOCKET NO. 160021-EI
1	Total Base Current Operating Revenues	$7,938,744[27]	$5,922,205[28]
2	Requested Rate Increase	$1,108,442[29]	$866,354[30]
3	Total 2026 Revenue (non-fuel)	$9,047,186[31]	$6,788,559[32]
4	Total Rate Base Request	$55,507,996[33]	$32,536,116[34]
5	Weighted Equity Cost @ 11.90% ROE	5.52%[35]	5.19%[36]
6	Federal Income Tax Gross-up	1.265823[37]	1.515151[38]
7	WEIGHTED RETURN & TAX	6.987%[39]	7.8636%[40]
8	Total Profit and FIT	$3,878,533[41]	$2,558,521[42]
	Equity Return and FIT as a Percent of Base Revenues	42.80%[43]	37.69%[44]

[27] See Docket No. 20210015-EI MFR C-1 Test Year 12/31/2022, line 5, column 10.
[28] See Docket No.160021-EI MFR C-1, Test Year 12/31/2017 line 5, column 10.
[29] See Docket No. 20210015-EI MFR A-1 Test Year 12/31/2022, line 16, column 3.
[30] See Docket No.160021-EI MFR A-1 Test Year 12/31/17 Line 16, column 3.
[31] Sum of lines 1 and line 2.
[32] Sum of lines 1 and line 2.
[33] See Docket No. 20210015-EI MFR A-1 Test Year 12/31/2022 line 2, column 3.
[34] See Docket No.160021-EI MFR A-1, Test Year 12/31/2017 line 2, column 3.
[35] See Docket No. 20210015-EI MFR D-1a, Test Year 12/31/2022 line 8, column 11.
[36] See Docket No.160021-EI MFR D-1a, Test Year 12/31/2017, line 4, column 11.
[37] Calculated as 1/(1-Corporate Tax Rate) or 1/(1-21%) in the 2021 rate case.
[38] Calculated as 1/(1-Corporate Tax Rate) or 1/(1-35%) in the 2016 rate case.
[39] Line 5 * line 6.
[40] Line 5 * line 6.
[41] Line 7 * line 4.
[42] Line 7 * line 4.
[43] Line 8/line 3.
[44] Line 8/line 3.

As shown on Tables 5 and 6, each time FPL files a case the equity return component as a percentage of base rates increases substantially. Now in the current case, FPL's equity returns are at almost 50 cents of every base rate dollar paid by consumers.

Q. WHY ARE FPL'S EQUITY AND INCOME TAX LEVELS SUCH LARGE AND INCREASING COMPONENTS OF BASE RATES?

A. One reason is that a large portion of revenues in Florida are collected through various clauses and surcharges and not in base rates. This will impact base rate levels. Another factor is high growth in rate base will increase equity return and federal income tax components, thus FPL's rate base growth has an impact. A third factor is the equity return level and how capital is financed, i.e. capital structure. FPL has enjoyed higher equity return awards and has been authorized to maintain very high 59.6% equity levels in capital structure. Comparable electric utilities around the country are authorized much lower equity levels in capital structure, on average about 52% equity in capital structure. The 7.6% difference (59.6% FPL equity level – the 52% average utility equity level) is substantial especially at high equity return levels. For example, under FPL's proposal, the weighted debt cost is 1.51%.[45] FPL's proposed equity cost in this case grossed up for federal income taxes is 7.54%.[46] Capital expansion costs substantially more when most of expansion is financed at a cost of 7.54% equity versus a 1.51% debt rate. FPL has had and continues to have large capital expenditures, and with the higher equity return levels and equity rich capital structures, this makes equity financing the most expensive financing for consumers.

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[45] See FPL's MFR Schedule D-1a, line 8, column 11 5.96% grossed up for tax factor 1.2658.
[46] See FPL's MFR Schedule D-1a, line 8, column 11 5.96% grossed up for tax factor 1.2658.

Q. HAVE YOU EVALUATED OTHER FLORIDA ELECTRIC UTILITY OPERATIONS IN TERMS OF PERCENTAGE PROFIT RECOVERY IN BASE RATES?

A. Yes. I have evaluated profit requests relative to base rate revenues for the recent Duke Energy Florida, LLC (Duke Florida) case (Docket No. 20240025-EI) from last year. Duke Florida, a large Florida electric utility, operates under the same clauses and rules as FPL. The difference is Duke Florida employs a 53% equity ratio for financial operations, which is much lower than FPL's 59.6% equity ratio. The summary results of this analysis of Duke Florida compared to the FPL profit request is summarized in Table 7:

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TABLE 7[47]

SUMMARY COMPARISON OF SHAREHOLDER PROFIT REQUEST AS A PERCENT OF BASE RATE REVENUES FPL VERSUS DUKE

LINE		DUKE ENERGY FLORIDA Docket No. 20240025-EI	FLORIDA POWER & LIGHT Docket No. 20250011-EI
1	Total Base Current Operating Revenues	$2,969,785[48]	$9,884,769[49]
2	Requested Rate Increase	$593,446[50]	$1,544,780[51]
3	Total 2026 Revenue (non-fuel)	$3,563,231[52]	$11,429,549[53]
4	Total Rate Base Request	$20,534,271[54]	$75,129,676[55]
5	Weighted Equity Cost @ 11.15% ROE for Duke and 11.90% for FPL	5.09%[56]	5.96%[57]
6	Federal Income Tax Gross-up	1.265823[58]	1.265823[59]
7	Equity return w/ Federal Income Tax Gross-up	6.443%[60]	7.5443[61]
8.	Total Profit and FIT	$1,323,031[62]	$5,668,011[63]
9.	Equity Return and FIT as a Percent of Base Revenues	37.13%[64]	49.59%[65]

[47] These shareholder profit calculations are shown in Exhibit (DJL-2).
[48] Duke Energy Florida Docket No. 20240025-EI, MFR C-1, Test Year 12/31/2025, line 5, column 8.
[49] See MFR C-1 Test Year 12/31/2026, line 5, column 10.
[50] Duke Energy Florida Docket No. 20240025-EI< MFR Schedule A-1, Test Year 12/31/2025, line 8, column C.
[51] See MFR A-1 Test Year 12/31/2026, line 8, column 3.
[52] Sum of lines 1 and 2 above.
[53] Sum of lines 1 and 2.
[54] Duke Energy Florida Docket No. 20240025-EI -MFR Schedule A-1, Test Year 12/31/2025, line 1, column C.
[55] See MFR A-1 Test Year 12/31/2026, line 1, column 3.
[56] Duke Energy Florida Docket No. 20240025-EI- MFR Schedule D-a1, Test Year 12/31/2025, line 1, column 12.
[57] See MFR D-1a Test Year 12/31/2026, line 8, columns 10 and 11.
[58] Federal income tax gross-up = 1/(1-FIT Rate of 21%).
[59] Federal income tax gross-up = 1/(1-FIT Rate of 21%).
[60] Line 5 * line 6.
[61] Line 5 * line 6.
[62] Line 7 * line 4.
[63] Line 4 * line 7.
[64] Line 8/line 3.
[65] Line 8/line 3.

As shown in Table 7, at line 9, the FPL shareholder profit and income tax as a percentage of base rates is by far much higher than Duke Florida even though both utilities operate in Florida and face the same regulatory and other risks. The key difference is that Duke Florida employs a higher percentage of debt to finance the system rate base investment. I discuss capital structure in more detail in Section IX "Capital Structure."

Q. DOES FPL HAVE A HIGHER PROFIT PROPOSAL BECAUSE THEY HAVE A DIFFICULT TIME EARNING THE AUTHORIZED RETURN?

A. If recent history is to be a guide, the answer is no. FPL not only consistently reported earning the authorized return on equity midpoint of 10.8% but also earned upwards of an additional 100 basis point in most months since the last case for the period January 2022 - January 2025.[66] I have included in Exhibit (DJL-2) a summary of FPL's earned equity return by month as reported by FPL to the Commission in the monthly Rate of Return Surveillance Reports. As shown in Exhibit (DJL-2), on a monthly basis FPL generally earned about 100 basis points above the authorized equity return midpoint.

Q. IS FPL REQUESTING A HIGHER SHAREHOLDER PROFIT LEVEL IN THIS CASE?

A. Yes, the Company is requesting a shareholder profit level of 11.90%, which is 110 basis points above the current authorized 10.80% midpoint equity return. The equity return increase of 110 basis points impact on the Company's requested rate increase is summarized in the following Table 8:

[66] FPL's midpoint equity return was the result of a change required by the Settlement Agreement authorizing an increase in ROE in October 2023.

TABLE 8

FPL REQUESTED EQUITY RETURN PROFIT IMPACT ON INCREASE REQUEST FOR YEAR ENDING 12/31/2026 ($ MILLIONS)

LINE	DESCRIPTION	FPL REQUESTED ROE 11.90% AMOUNT (000's)	FPL CURRENT ROE 10.80% AMOUNT (000's)	SOURCES
1	RATE BASE	$75,129,876	$75,129,876	MFR SCHEDULE B-1
2	ROR	7.63% @ 11.90% ROE	7.08% @ 10.80% ROE	MFR SCHEDULE D1-A, also see Exhibit (DJL-11 slide 3) for 10.8% ROE.
3	REQUESTED RETURN	$5,731,953	$5,319,195	LINE 1 * LINE 2
4	CURRENT INCOME	$4,580,123	$4,580,123	MFR SCHEDULE C-1
5	DEFICIENCY (EXCESS)	$1,151,831	$739,072	LINE 3 - LINE 4
6	INCOME GROSS-UP	1.34115	1.34115	MFR SCHEDULE C-44
7	REVENUE REQUIREMENT	$1,544,780	$991,206	LINE 6 * LINE 7
8	DIFFERENCE		$(553,574)	ANNUAL IMPACT OF 10.80% ROE INCREASE TO 11.90%

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As demonstrated in Table 8, the Company's requested 110-basis point increase in shareholder profit accounts for $553,574,000 of the requested $1,544,780 first year increase. Over the four-year Rate Plan, this amounts to over $2.2 billion of increased consumer rates for higher shareholder profits and associated federal income taxes.

Q. DOES THE UTILITY BENEFIT FROM A MULTI-YEAR RATE PLAN?

A. Yes. First, the utility benefits by having planned and locked-in rate increases to address forecasted revenue changes, cost changes, and investment changes. This will prevent, or at least minimize, earnings erosion and maintain of profits and cash flow metrics. It also minimizes regulatory lag associated with the processing of rate changes by having predetermined rate changes (or other adjustments e.g., TAM) for different plan years, which in turn enhances cash flow metrics, and the quality of earnings that are maintained through periodic cash and in some instances non-cash increases. From a ratepayer perspective, a rate plan shifts regulatory lag risks to consumers, but from the Utility's perspective, these periodic increases provide certainty of recovery of planned investment and avoid all regulatory lag and earnings erosion due to these investments. Such planned increases limit and reduce risk and enrich a utility's financial health. One way to see these benefits is to review the FPL earnings for January 2022 through January 2025 in Exhibit (DJL-2) where the Company was able to earn substantially above the authorized midpoint equity return in most months over the rate periods.

Q. ARE THE RISKS OF REGULATORY LAG AND EARNINGS EROSION SHIFTED TO CUSTOMERS IN A MULTI-YEAR RATE PLAN?

A. Yes. The Company developed and controls the plan into the future. To the extent the revenue forecast is understated, expense forecast is overstated, or planned investment schedules are slower than projected, the Company will earn added profits. Any risks of regulatory lag and earnings erosion do not vanish – rather, customers will now have those risks in the form of paying higher rates for higher utility profits.

Q. DO YOU MAKE A RECOMMENDATION ON THE PROPOSED MULTI-YEAR RATE PLAN?

A. No. Other OPC expert witnesses will address forecasts and rate plan issues. I just outline the evidence and facts as such evidence and facts relate to cost of capital and support the lower utility risks associated with the proposed multi-year plan.

III. REGULATORY ISSUES AND COST OF CAPITAL

Q. PLEASE EXPLAIN THE COST OF CAPITAL CONCEPT AS IT RELATES TO THE REGULATORY PROCESS.

A. The overall rate of return to be earned on rate base investment is an essential element in the regulatory and rate setting process and is typically a major part of overall revenue requirements. For example, in this case, the Company's requested overall return for rate year 2026 (the first year of the rate plan) is 7.63%.[67] As is discussed earlier, a 110-basis point reduction in the 11.90% rate of return on equity (to a 10.80% level) can have a large impact on overall revenue requirements. As shown in the Table 8 above, a 110-basis point reduction in equity return in the 2026 test year would result in an approximate $553.574 million per year reduction in annual revenue requirements including the impact of the federal income tax gross-up factor for electric customers.[68] Stated another way, each equity return basis-point in this case impacts revenue requirements (return and federal income

[67] See FPL MFR Schedule A-1 line 2 and MFR Schedule D-1.
[68] Tax Factor equal 1/(1-tax rate), which is (1/(1-.21)) equals 1.26582. This tax factor of 1.26582 times the requested shareholder profit level requested equals taxes and profits.

taxes) by about $5.03 million ($553.574 mm/ 110-basis points). Given the Company proposal for a four-year rate plan, each basis point translates into over $20 million (4 * $5.033 mm) in just the 2026 test year. Thus, any change in equity return can have a large impact on revenue requirements for consumers.

Q. PLEASE EXPLAIN HOW THE VARIOUS COMPONENTS OF COST OF CAPITAL ARE DETERMINED.

A. The overall rate of return in the regulatory process is best explained in two parts. First, return on securities, such as long-term debt and short-term debt, both of which are included in the capital structure, are contractually set at issuance. The reasonableness of the cost of this contractual obligation between the utility and its investors is examined by regulatory agencies as part of the utility's overall revenue requirement.

The second part of a company's overall return requirement is the appropriate cost rate to assign the equity portion of capital costs. The return on equity should be established at a level that will permit the Company an opportunity to earn a fair rate of return. By fair rate of return, I mean a return to equity holders, which is sufficient to hold and attract capital, sufficient to maintain financial integrity, and a return to equity holders comparable to other investments of similar risks.

Two U.S. Supreme Court decisions are often cited as the legal standards for rate of return determination. The first is *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262. U.S. 679 (1923). The *Bluefield* case established the following general standards for a rate of return: The return should be sufficient for maintaining financial integrity and capital attraction, and a public utility is entitled to a return equal to that of its investments of comparable risks.

The second U.S. Supreme Court decision is the *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944). In the *Hope* decision, the Court affirmed its earlier *Bluefield* standards and found that methods for determining return are not the test of reasonableness; rather, the result and impact of the result are controlling.

The cost of capital is defined as the annual percentage that a utility must receive to maintain its financial integrity, to pay a reasonable return to security owners, and to ensure the continued attraction of capital at a reasonable cost and in an amount adequate to meet future needs. Mathematically, the cost of capital is the composite of the cost of several classes of capital used by the utility such as debt, preferred stock, and common stock, weighted on the basis of an appropriate capital structure.

The ratemaking process requires the regulator to determine the utility's cost of capital for debt, preferred stock, and equity costs. These calculations of costs, when combined with the proportions of each type of capital in the capital structure, result in a percentage figure that is then multiplied by the value of assets (investment) used and useful in the production of the utility service to ultimately arrive at a rate charged to customers. Rates should not be excessive (exceed actual costs) or burdensome to the customer and at the same time should be just and reasonable to the utility.

Q. PLEASE EXPLAIN THE COST OF EQUITY CONCEPT.

A. The cost of equity, or return on equity capital, is the return expected by investors over some prospective time period. The cost of equity one seeks to estimate in this proceeding is the return investors expect prospectively when the rates from this case will be in effect.

The cost of common equity is not set by contract, and there are no hard and fast mathematical formulae with which to measure investor expectations with regard to equity requirements and perceptions of risk. As a result, any valid cost of equity recommendation must reflect investors' expectations of the risks facing a utility.

Q. WHAT PRINCIPAL METHODOLOGY DO YOU EMPLOY IN YOUR COST OF EQUITY CAPITAL ANALYSES?

A. I employ the DCF methodology for estimating the cost of equity, keeping in mind the generally accepted premise that any utility's cost of equity capital is the risk-free return plus the premium required by investors for accepting the risk of investing in an equity instrument. It is my opinion that the best analytical technique for measuring a utility's cost of common equity is the DCF methodology. I also employ the two-stage DCF to reflect different growth rate assumptions. Other return on equity modeling techniques such as the CAPM, ECAPM, and bond yield equity risk premium model are often used to check the reasonableness of the DCF results. I have reviewed all of these modeling methods to arrive at my recommendations in this case.

Q. PLEASE DESCRIBE THE RISKS YOU REFER TO ABOVE.

A. As I stated earlier in this testimony, equity investors require compensation above and beyond the risk-free return because of the increased risk factors investors face in the equity markets. Thus, investors require the risk-free return plus some risk premium above the risk-free return. The basic risks faced by investors that make up the equity risk premium include business risks, financial risks, regulatory risks, and liquidity risks.

IV. CURRENT CAPITAL MARKET CONDITIONS

Q. PLEASE DESCRIBE CURRENT AND EXPECTED ECONOMIC CONDITIONS.

A. Current economic conditions reflect declining, but still elevated inflation, a moderate loosening of monetary policy, and since the fourth quarter of 2024, decreasing federal funds, short-term interest rates, stable and expected declines for interest rates in general, lower growth with signs of negative growth in Gross Domestic Product ("GDP"), and a strong labor employment market.

Following a prolonged period of low-price pressures in the economy from 2012 through 2019, the CPI had been at 2.5% or lower, but this trend changed as discussed below.[69] Throughout the first year of the pandemic from March 2020 through February 2021, the CPI was below 2.0%.[70] Starting in March 2021, CPI began to climb above 2.5%, and the CPI increase had been steady until the reports of 8.6% for May 2022, 9.1% for June 2022, and thereafter declining in July 2022 to 8.5%.[71] The 9.1% CPI for June 2022 is the largest 12-month increase since the 12-month period ending November 1981.[72] The most recent Bureau of Labor Statistics ("BLS") report for April 2025 shows a 2.3% inflation rate over the prior 12 months.[73] CPI has substantially declined from the 9.1% high in response to monetary policy actions raising the federal funds rate.

As discussed below, the Federal Reserve employs the Personal Consumption Expenditure ("PCE") metric for measuring long-run inflation. During recent months, the annual measure of the PCE price index is as follows:

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[69] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 19 (June 10, 2022).
[70] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 19 (June 10, 2022).
[71] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (June 10, 2022) and U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (July 13, 2022) and August 10, 2022.
[72] U.S. Department of Labor Bureau of Labor Statistics, News Release at page 1 (July 13, 2022).
[73] U.S. Department of Labor Bureau of Labor Statistics, News Release "Consumer Price Index" (May 13, 2025).

Table 9[74]

PERSONAL CONSUMPTION EXPENDITURES PRICE INDEX NOVEMBER 2024 THROUGH APRIL 2025

November 2024	**2.5%**
December 2024	**2.6%**
January 2025	**2.5%**
February 2025	**2.5%**
March 2025	**2.3%**
April 2025	**2.1%**

Inflation has declined substantially whether measured by the CPI or PCE index. As demonstrated in the above Table 9, the PCE rate had been holding steady at around 2.5%, about 50 basis points above the Federal Open Market Committee ("FOMC") 2.0% target rate and has most recently trended down to 2.1%.

Q. WHAT HAS BEEN THE RECENT FEDERAL RESERVE RESPONSE TO INFLATION?

A. When addressing inflation, the Federal Reserve and FOMC look to the percent change in inflation as measured by the metric PCE as the primary measure of price changes when determining and implementing long-term monetary policy goals.[75] The FOMC has

[74] Personal Consumption Expenditures Expenditure Price Index, Bureau of Economic Analysis ("BEA") also see bea.gov/data/personal-consumption-expenditures-price-index (April 16, 2025). Also, see April 30, 2025 release for March 2025 and see the May 30, 2025 release for April 2025.

[75] *President's Message: CPI vs. PCE Inflation: Choosing a Standard Measure,* Federal Reserve Bank of St. Louis (July 1, 2013) at page 2, The Federal Reserve has employed the PCE inflation metric rather than the CPI measure since about 2000 in setting long-term monetary policy. After extensive analysis the Federal Reserve selected the PCE metric because: i) the expenditure weights in the market basket measure change as consumers substitute goods and

consistently increased the federal funds rate as part of a tightening of monetary policy to reduce inflation. In July 2023, the FOMC increased the federal funds rate by 25 basis points from 5.25 to 5.50%, the peak of the recent increases in the federal funds rate increases.[76] Additionally, during the post COVID-19 higher inflation period, the FOMC further tightened liquidity by reducing its balance sheet by reversing the Quantitative Easing programs.[77]

Now the federal funds rate has been reduced to a 4.25% to 4.5% range, or 100 basis points in reduction to the federal funds rate, and quantitative tightening has been slowed from $25 billion of redemption of treasury securities per month to $5.0 billion per month.[78]

The recent May 7, 2025, FOMC press release stated:

> in support of its goals, the Committee decided to maintain the target range for the federal funds rate at 4-1/4 to 4 1/2 percent. In considering the extent and timing of additional adjustments to the target range for the federal funds rate, the Committee will carefully assess incoming data, the evolving outlook, and the balance of risks.[79]

In the earlier March 19, 2025, the "Summary of Economic Projections," the FOMC members provided forecasts for the federal funds rate as follows:

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services, ii) the PCE market basket includes more comprehensive coverage of goods and services, and iii) historical PCE is subject to revision and correction beyond seasonality adjustments.

[76] Federal Reserve FOMC Statement July 26, 2023.

[77] Federal Reserve FOMC Statement June 15, 2022.

[78] Federal Reserve FOMC Statement March 19, 2025.

[79] Federal Reserve FOMC Statement May 7, 2025. Also see the most recent FOMC Statement of May 7, 2025 included in Exhibit (DJL-3).

TABLE 10[80]

CURRENT AND PROJECTED FEDERAL FUNDS RATE AND PCE INFLATION

Year	Federal Funds Rate[81]	PCE INFLATION
Current April 2025 level	4.50%	2.5%
Projected 2025	3.9%	2.7%
Projected 2026	3.4%	2.2%
Projected 2027	3.1%	2.0%
Longer--run	3.0%	

The most recent FOMC projections in Table 10 indicate decreases in the federal funds rate in 2025, 2026, 2027, and the longer-run. These FOMC projections indicate that the federal funds rate will decrease to 3.9% by year-end 2025. The federal funds rate is expected to be lowered to 3.4% by 2026 and 3.1% in 2027 with a longer-term goal of about 3.0% for this interest rate. Obviously, the current projections are all subject to change as the Federal Reserve delicately balances its dual mandate of reducing inflation while maintaining employment in the general economy.

Also, in the March 19, 2025 *Summary of Economic Projections*, the FOMC members provided forecasts for the PCE inflation rate in the United States will average 2.7% over the entire year 2025, decline to 2.2% for the year 2026, and further decline to 2.0% in the year 2027.[82]

[80] See FOMC Projections released March 19, 2025, in Exhibit (DJL-3).
[81] *Summary of Economic Projections*, Federal Open Market Committee, page 2 Table 1, Federal Funds Rate and PCE Inflation based on Median Projections (March 19, 2025). Current PCE rate based on February 2025 from March 19, 2025, Press Release.
[82] *Summary of Economic Projections*, Federal Open Market Committee, page 1 Table 1, PCE Inflation Median Projections (March 19, 2025).

Recent and continued 2024 - 2025 declining trends in inflation, whether measured by the CPI or PCE, have caused a slowing of tighter Federal Reserve monetary policy - signaling a continued move toward lower short-term interest rates. Current FOMC inflation estimates for 2025, and the long-term, support a lower 2.0% rate of inflation which suggests lower long-term interest and capital costs. Further, the current Federal reserve projections of 2025 federal funds rate indicates reductions for both the near term and longer-run future.[83] The end result is that cost of capital today should decline in the rate effective period 2026 and beyond.

Taken together, this information shows capital costs have trended higher for 2022 and into 2024, but short-term rates are forecast to return to lower levels in the near future. Certainly, there is no market evidence suggesting long-term capital costs are substantially increasing, which would be necessary to support FPL's ROE request in this case.

Q. ARE ECONOMIC CONDITIONS EXPECTED TO SHOW CONTINUED GROWTH IN THE 2025 - 2027 AND BEYOND PERIOD?

A. Yes, but FOMC forecasts of 2025 through 2027 GDP growth are lower than the earlier December 2025 estimates.[84] Forecasts are for continued but slower economic growth. If economic growth declines further due to recent changes in tariff and trade policy, causing recession factors such as unemployment increases coupled with a slowed and stagnant economy, then the FOMC will be pressured to back down the federal funds rate further to push GDP growth and employment while still balancing lower inflation goals. To this point, the most recent GDP report for the first quarter of 2025 shows GDP growth

[83] See Exhibit (DJL-3) FOMC March 19, 2025, projections.
[84] Federal Reserve FOMC Economic Projections March 19, 2025.

decreasing at an annual rate of 0.30%.[85] This is after the fourth quarter 2024 GDP increase of 2.4%. The decrease of GDP growth in the 1ST quarter 2025 is the result of "increased imports, which are a subtraction in the GDP calculation."[86] The Federal Reserve press release of May 7, 2025 noted that "swings in net exports have affected the data, recent indicators suggest that economic activity has continued to expand at a solid pace."[87] For now, the Federal Reserve does not appear overly concerned with the 1st quarter of 2025 GDP decline.

There is no evidence to support rapid economic growth pushing prices and inflation, but tariff impacts could push prices upwards. Instead, there is ample evidence of slow to possibly negative growth in economic conditions. The recent May 7, 2025, FOMC press released warned of uncertainties.[88]

I have included in Exhibit (DJL-3) the recent FOMC March 19, 2025, Press Release and economic projections and the May 7, 2025, FOMC Press Release. The FOMC's range of projections of GDP growth is 1.7% - 1.8% for the period 2025 - 2027, which is a decrease from earlier December 2024 estimates of GDP growth of 2.1% to 1.8% for the period 2025 - 2027. The 2025 to 2027 FOMC projections of employment levels are about the same as the earlier FOMC December 2024 estimates of employment levels.

Thus, while GDP growth continues in the U.S. economy, the growth in economic activity is slower than previously projected for GDP growth. In addition, the recent slowing of decreases in the federal funds rate and the accelerated end of the quantitative easing policy is a signal that the FOMC sees high and increasing inflation as being controlled for now. The impact has been declining short-term interest rates but lagging longer-term

[85] Bureau of Economic Analysis Gross Domestic Product, 1ST Quarter 2025(Advance Estimate) April 30, 2025, at 1. Also, see www,bea.gov/news/2025/gross-domestic-product-1st -quarter-2025-advance-estimate.
[86] see www,bea.gov/news/2025/gross-domestic-product-1st -quarter-2025-advance-estimate at 1.
[87] Federal Reserve FOMC Statement of May 7, 2025, included in Exhibit (DJL-3).
[88] Federal Reserve FOMC Statement May 7, 2025. Also, see Exhibit (DJL-3).

borrowing costs to consumers and businesses. As discussed above, the FOMC projects PCE inflation to be much lower in the 2025 period and beyond indicating lower future federal funds rates.

Q. DOES THE FACT THAT INTEREST RATES ARE DECREASING FROM THE FOURTH QUARTER 2023 HIGHS SUGGEST OTHER CAPITAL COSTS SUCH AS EQUITY ARE ALSO DECREASING?

A. As I show in Exhibit (DJL-4), the yields on long-term government bonds 10-year, 20-year, and 30-year peaked in the fourth quarter of 2023 and have been slowly declining. Capital costs do move together – so if interest rates are declining, the cost of other capital such as equity will decrease as well. The key difference is that equity and debt costs do not move in lock-step. In other words, debt costs may increase or decrease by 1.0%, but equity costs will change by a smaller fraction of 1.0%. This historical relationship can be seen in Exhibit (DJL-11) where the actual annual 30-year U.S. Treasury yield and authorized electric utility equity returns are presented for the period 1981 through 2024.

Since 1981, capital costs have been declining as evidenced by the long-term decline in electric utility authorized equity returns and the decline in 30-year U.S. Treasury yields. The decline in equity costs is a much slower trend with a lower slope, while debt costs have declined by larger margins, as evidenced by the data in the debt costs trend. For the period 1981 through 2024, the average of the absolute value annual change in 30-year U.S. Treasury bond yields is about 58 basis points.[89] For authorized electric utility equity returns over the same time period, the average absolute value annual rate of change is about 25 basis points or less than half the rate of change in U.S. Treasury yields.[90] Thus, while it

[89] See Exhibit (DJL-11) and Workpaper DJL-11.
[90] See Exhibit (DJL-11) and Workpaper DJL-11.

may be correct to conclude that debt costs will increase or decrease over the short-term, if history is a guide, equity cost changes and impacts on equity returns should be of a smaller magnitude.

The result of this comparative analysis is that while debt cost may be decreasing in the short-term, any expected equity cost change is less than half the level debt rate changes. At least, that has been the historical experience when debt cost was declining for the past 40 years.

Q. WHAT LEVEL OF INTEREST RATES DO YOU EMPLOY FOR YOUR COST OF CAPITAL ANALYSIS?

A. I generally employ the most current three-month average as the best approximation of interest rate levels. Generally, the most recent three-months of activity adequately captures the market expectations and trends of interest rates while avoiding any limited influences of monthly or shorter durations may have on interest rates. Given the most recent 2024 reductions in the Federal Funds rate and projections of further declining rates, I also employ a 4.25% estimate for yields for the 30-year treasury bond to capture the impacts from the most recent expectations in Federal Reserve policy.

Q. WHAT LEVEL OF INTEREST RATES DO YOU EMPLOY FOR YOUR COST OF MOST RECENT ASSESSMENTS OF ECONOMIC GROWTH?

A. Yes. I discussed earlier the current estimates of the FOMC that reflect moderate GDP growth expected in 2025 - 2027, and the long-run. It is important to note that the recent FOMC estimates and projections are supported by recent forecasts in the Livingston

Survey.[91] The December 2024 Livingston Survey estimates GDP growth for the first half of 2025 at 1.9% which is slightly higher than the 1.7% FOMC GDP growth estimate discussed above.[92] Like the FOMC inflation estimates, the Livingston Survey forecasters also lowered projections for CPI inflation to 2.3% for 2025 and 2026 from prior 2.5% estimates.[93] These Livingston Survey forecasters also reduced the forecast estimates 3-month Treasury Bill (short-term interest rates), but slightly increased longer-term interest rates as measured by the 10-year U.S. Treasury Bond.[94] Thus, the immediate short-term forecasts for inflation and interest rates have decreased, and estimates of economic growth are declining. Thus, private forecasting groups (that participate in the Livingston Survey) are estimating the same short-term decreasing levels of interest costs and inflation coupled with lower economic growth as the Federal Reserve is estimating.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM CURRENT ECONOMIC CONDITIONS IN PROVIDING GUIDANCE IN SETTING EQUITY CAPITAL COSTS IN THIS PROCEEDING?

A. As a general matter, capital costs remain low in comparison to historical levels. During 2024, the average authorized equity returns for electric utilities was about 9.73%.[95] Thus, the most recent average authorized equity return for electric utilities is 217 basis-points lower than the Company's 11.90% request. A 217-basis point reduction in equity return, or average electric industry equity return, would reduce the first-year rate request from $1.544 billion by about $1.094 billion which is a little over $1 billion per year in the 4-year

[91] The Livingston Survey is the oldest continuous survey of economist's economic expectations, published twice per year (June and December). Included in the work papers of Mr. Lawton. Also, see www.philadelphiafed.org.
[92] The Livingston Survey December 20, 2024. www.philadelphiafed.org
[93] The Livingston Survey December 20, 2024 at 1. www.philadelphiafed.org.
[94] The Livingston Survey December 20, 2024 at 2. www.philadelphiafed.org.
[95] See Edison Electric Institute ("EEI") Rate Review 2024 Quarter 4.

Rate Plan.[96] These recent authorized equity returns do not support the Company's equity return request of 11.90%. The current forecast for modest economic growth (GDP growth) will cause general investor expectations of growth to continue to be moderate. The bottom line is that the general economic data does not support substantially increasing capital costs.

Q. HAVE REGULATORY AUTHORITIES AROUND THE COUNTRY RECOGNIZED THE DECLINE IN COST OF EQUITY AND DEBT CAPITAL IN SETTING RATES?

A. Absolutely. Regulatory authorities continue to establish equity returns below 10%. The average annual authorized equity return for electric utility companies has been below 10% since 2014.[97] As noted earlier, regulatory authority cost of equity decisions for electric utility rate cases for calendar years – 2023 - 2024 averaged about 9.59% and 9.69%[98] Moreover, the last time authorized equity returns were as high as 11.90% annually was 1992 - 33 years ago.[99] Capital market levels and trends have changed with declining inflation and more moderate monetary policy, but given market evidence, monetary policy, and current forecasts by the FOMC and the Livingston Survey results, there is no evidence that would support substantially increasing the cost of capital to the requested 11.90%.

I should note that much of the discussion has addressed the size (11.90%) of the profit request, but this profit request impact is made worse for customers given the equity portion of capital in capital structure. In this case, like prior cases, FPL is requesting a capital structure that includes a 59.60% equity ratio. As I discuss in Section IX "Capital

[96] The 1.094 billion reduction is calculated as $5.040 mm per basis point times 217 basis points.
[97] See Exhibit (DJL-11).
[98] See Exhibit (DJL-11).
[99] See Exhibit (DJL-11) Authorized equity returns by year.

Structure," the average electric utility has about a 52% equity ratio, well below the Company's 59.6% request. A lower equity ratio makes customers rates cheaper as assets are financed with lower cost debt rather than higher cost equity.

V: FPL AND THE FLORIDA REGULATORY PROCESS

Q. DOES THE REGULATORY PROCESS IN FLORIDA AFFORD THE COMPANY RISK REDUCING OPPORTUNITIES?

A. Yes. The regulatory process in Florida provides ample opportunity to recover revenues, address regulatory lag concerns, and promote earned returns and margins over and above cost recoveries. The Florida Commission's supportive regulatory environment includes regulatory mechanisms such as subsequent year adjustments to avoid regulatory lag when justified, forward-looking test periods, negotiated multi-year settlement rate plans, revenue recovery mechanisms such as fuel and capacity recovery mechanisms, environmental cost recovery clauses, storm hardening cost recovery, ability to petition for storm cost recovery outside a base rate proceeding, credit supportive storm cost treatment, and an overall credit supportive regulatory environment.[100] While Moody's points to risk of storms and the cost impacts on credit metrics, Moody's also points out that the Florida Legislature provides timely storm hardening cost recovery.[101]

All of these credit supportive regulatory mechanisms help offset the impacts of regulatory lag, enhance cash flow, and strengthen financial integrity.

Q. CAN YOU PROVIDE AN EXAMPLE OR EVIDENCE THAT FPL IS LESS RISKY?

[100] See Moody's Investor Services Credit Opinion Duke Energy Florida pages 1 - 4, (May 22, 2023).
[101] See Moody's Investor Services Credit Opinion Duke Energy Florida page 1.

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A. Yes. Risk for shareholders is measured as the ability of a firm to earn a reasonable return on equity. In the case of a regulated utility, the reasonable return on equity is established by the regulatory authority. Below, I include a table of actual earned returns by FPL relative to the average authorized equity returns around the country for the years 2022 through 2024.

TABLE 11

AUTHORIZED AVERAGE EQUITY RETURNS VERSUS EARNED EQUITY RETURNS FOR FPL 2022- 2024[102]

YEAR	FPL ROE BOTTOM RANGE	FPL ROE MID-POINT	FPL ROE TOP RANGE	FPL ACHIEVED ROE	ACTUAL AVERAGE AUTHORIZED RETURN ELECTRIC UTILITIES
2022 through September	9.70%	10.60%	11.70%	11.60%	9.46%
2022 October	9.80%	10.80%	11.80%	11.80%	9.46%
2023	9.80%	10.80%	11.80%	11.80%	9.59%
2024	9.80%	10.80%	11.80%	11.80%	9. 69%

As can be seen from Table 11, FPL has been able to achieve an actual equity return at the top of the range in two of the three years and the first year was about 20-basis points below the top of the 11.80% range. Also, in each year, FPL earned more than 200 basis points above the average authorized equity return in the entire country, all while maintaining a 59.6% equity ratio. These earned return results demonstrate that FPL has operated in a

[102] Data from FPL earnings surveillance reports also see Exhibit (DJL-2). Actual annual average authorized equity returns from Exhibit (DJL-11).

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regulatory environment where the Company has consistently earned its authorized returns – even in what can be described as a turbulent economic environment given the COVID-19 impacts on the economy in recent years. This evidence does not support the Company's proposal that the FPL equity return should now be increased another 110 basis points and set at 11.90%, which is about 200-basis points above current authorized equity return levels.

Q. EARLIER YOU MENTIONED REGULATORY LAG. HOW DOES THIS LAG IMPACT RATE SETTING AND REGULATORY RISK?

A. Regulatory lag is the period of time it takes to adjust tariffs in a rate case proceeding. Generally, it is the time between the utility rate request and the realization of a needed rate adjustment and the ultimate authorization of a rate change. For example, a utility requesting a rate increase of $1 million based on a historical test year may claim earnings erosion due to the regulatory lag during the pendency of the rate process until the authorized increase is implemented.

The counter argument to these claims of regulatory lag and risk is that the utility controls the timing of its rate requests. Also, regulatory lag is built into the regulatory process to encourage the utility to control and monitor costs as a means of bolstering profits. Regulatory lag can work both ways – sometimes there is earnings erosion while other times there can be excess earnings.

Other contributions to regulatory lag are increasing costs, inflation, increasing capital investments, and lower growth and sales. The regulatory process in Florida provides the Company ample opportunity to earn its authorized return by mitigating regulatory lag and maintaining cash flows and liquidity in the rate process.

Q. DO THE CREDIT RATING AGENCIES SUCH AS MOODY'S VIEW RATE MECHANISMS FAVORABLY?

A. Yes. Rating agencies are foremost concerned with a utility's ability to recover costs and earn an adequate return to cover expenses and debt obligations with a margin of safety on top of costs. For example, Moody's states a "utility's ability to recover its costs and earn an adequate return are among the most important analytical considerations when assessing utility credit quality and assigning credit ratings."[103] In terms of rate mechanisms and the impacts of reducing risks, Moody's states the following:

> One of the most referenced, but potentially misleading, indicators used to judge whether a particular utility is recovering its costs and earning an adequate return is its regulatory allowed return on equity. Although a high allowed return on equity can be associated with a higher earned return, this measure cannot be looked at in isolation but must be viewed in relation to a utility's cost recovery provisions that impact actual earned rate of return, like automatic adjustment clauses, the length of rate cases, and the degree of regulatory lag that may occur. Some regulators believe that mechanisms like automatic adjustment clauses materially reduce the business and operating risks of a utility, providing justification for a relatively low allowed rate of return. We believe this is one of several reasons why both allowed and requested ROE's have trended downward over the last two decades.[104]

Moody's concludes that the more clauses a utility has in place, the lower the risk for the utility.[105]

Q. DOES THE COMPANY FACE ANY UNUSUAL BUSINESS OR FINANCIAL RISK?

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[103] *"Cost recovery Provisions Key To Investor- Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) at page 1.
[104] *"Cost recovery Provisions Key To Investor-Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) at pages 1-2.
[105] *"Cost recovery Provisions Key To Investor-Owned Utility Ratings and Credit Quality*, Evaluating a Utility's Ability to Recover Costs and Earn Returns," Moody's Investors Service Special Comment (June 18, 2010) at page [illegible].

A. FPL does propose a continuation of a large construction program over the next several years for solar facilities and other assets which will increase the size of rate base as planned projects go into service.[106] Mr. Coyne testifies that the expected 2025 - 2028 CAPEX is about $39 billion or roughly $9.75 billion per year.[107] As with many large scale utility construction projects, there is an expectation that cash flow metrics will be impacted over the construction period until all facilities are included in rates, then cash flow metrics will increase as cash flow increases.

Q. IN YOUR OPINION, CAN A HIGH EQUITY RETURN WHEN COMBINED WITH COST RECOVERY MECHANISMS LEAD TO EXCESS PROFITS AND EXCESSIVE OR UNREASONABLE RATES?

A. Yes, it can. I have described how the cost recovery mechanisms assure stable and consistent recovery despite: (i) consumer usage preferences, conservation levels and demand; (ii) fuel cost increases; and (iii) capital additions which may be recovered through negotiated multi-year rate plans or system hardening mechanisms, or capital replacement due to storm damage recovered through storm cost recovery mechanisms. Through such mechanisms, revenue recovery is stable and consistent assuring cash flow for corporate needs and profit levels. Risk as measured by volatility of return is addressed by these cost recovery mechanisms. Equity return levels are a function of risk levels so if risk is addressed in the mechanisms – a higher equity return authorization like 11.90% would overcompensate risk and result in unfair or unreasonable rates.

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[106] Direct testimony witness Ina Laney at page 27, lines 14 - 17 and page 39, lines 17 - 20.
[107] See Direct Testimony James Coyne at page 45, lines 6 - 10.

VI: COMPARABLE GROUP ANALYSIS

Q. PLEASE EXPLAIN AND DESCRIBE THE STARTING POINT OF YOUR COST OF CAPITAL ANALYSIS FOR THIS CASE.

A. The first step for any cost of equity capital analysis is the selection of a comparable group of companies for which market data is available to conduct a market-based cost of capital analysis. I reviewed Mr. Coyne's eight risk screening criteria for his comparable group analysis and selection. I agree with most of Mr. Coyne's selection or screening criteria for the comparable group analysis in this case.[108] I have removed TXNM Energy, as it currently is in the midst of a buy-out and merger. Given Mr. Coyne's comparable group selection criteria, I expect he will remove TXNM in his rebuttal testimony.

The 14-company comparable utility group is shown in the following Table 12:

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[108] Direct Testimony James Coyne at pages 29 - 30.

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Table 12

COMPARABLE RISK GROUP

ELECTRIC UTILITY GROUP	SYMBOL
ALLIANT ENERGY CORP	LNT
AMEREN CORPORATION	AEE
AMERICAN ELECTRIC POWER	AEP
DUKE ENERGY CORPORATION	DUK
EDISON INTERNATIONAL	EIX
ENTERGY CORPORATION	ETR
EVERGY, INC.	EVRG
IDACORP, INC.	IDA
OGE ENERGY CORPORATION	OGE
PINACLE WEST CAPITAL CORP	PNW
PORTLAND GENERAL ELECTRIC CO.	POR
PPL CORPORATION	PPL
SOUTHERN COMPANY	SO
XCEL ENERGY	XEL

All of these companies are dividend-paying electric utilities with investment grade bond ratings. I have included a listing in Exhibit (DJL-5) of the electric utilities in the comparable group along with basic data for beta, historical, forecasted equity ratios, and a forecast of comparable earnings from the Value Line data base.

VII: COST OF CAPITAL MODELS DCF ANALYSIS

Q. PLEASE EXPLAIN THE CONSTANT GROWTH DCF METHODOLOGY YOU HAVE EMPLOYED IN YOUR ANALYSIS.

A. The price that an investor is willing to pay for a share of common stock today is determined by the income stream the investor expects to receive from the investment. The return the investor expects to receive over the investment time horizon is composed of: (i) dividend payments; and (ii) the appreciated sale value of the investment. A proper analysis adds dividends to the gain on the final sale value, and discounts these expected future earnings to a present value.

To determine or estimate investor requirements using the DCF model, one computes a cost of capital requirement, or discount rate from the current market data and the expected dividend stream. The DCF model stated as a formula is as follows:

$$K = D/P + G$$

where:
K = required return on equity,
D = dividend rate,
P = stock price,
D/P = dividend yield, and
G = growth in dividends.

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE DIVIDEND YIELD FOR THE COMPARABLE COMPANIES.

A. The dividend yield is the ratio of the dividend rate to the stock price. When calculating the dividend yield, one must be cautious and not rely on spot stock prices. One must be equally cautious not to rely on long periods of time as the data becomes unrepresentative of market conditions. The objective is to use a period of time such that the resulting dividend yield is representative of the prospective period when rates will be in effect.

While there is no fixed period for selecting the denominator of the dividend yield (i.e., stock price), the key guideline is that the yield not be distorted due to fluctuations in stock market prices. On the other hand, dividends (the numerator of the yield calculation) are relatively stable as opposed to the stock prices, which are subject to daily and cyclical market fluctuations. The selection of a representative time period will dampen the effect of stock market changes.

The price and dividend data used for each of the proxy companies in the comparable group is contained in my Exhibit (DJL-6).

I have examined weekly closing stock prices for the 3-month period of February 17, 2025, through May 5, 2025, along with the 52-week high and low averages, to calculate a representative price for the dividend yield calculation. For this analysis, I have employed the recent 3-month average price (February 2025 through May 2025) in calculating the dividend yield.

To calculate dividends, I employ the current annualized dividend, increased for one-half of the expected growth rate. Because utility companies tend to increase quarterly dividends at different times throughout the year, the assumption is that dividend increases will be evenly distributed over the calendar quarters for the comparable group companies. Given the above, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term estimates of growth to the current dividend yield. I have calculated the yield employing the current dividends for each comparable company as reported by Value Line and the recent three-month average price and the resulting dividend yields are shown in my Exhibit (DJL-7).

Q. EXPLAIN HOW YOU HAVE CALCULATED THE EXPECTED GROWTH RATE IN YOUR CONSTANT GROWTH DCF ANALYSIS FOR THE COMPANIES IN

THE COMPARABLE GROUP.

A. Like the dividend yield, there exists no single or simple method to calculate growth rates. The calculation of investor growth expectations is the most difficult part of the DCF analysis. To estimate investor expectations of growth, I have examined historical growth, forecasted growth rates, and other financial data for each of the companies in the comparable group.

Implementation of the DCF model requires the exercise of considerable judgment with regard to estimating investor expectations of growth. It is a difficult task, but such difficulties are not insurmountable. Many economic factors affect capital markets in general and individual stocks specifically. Such economic variables, which were discussed earlier, entail the current state of the economy, including the trade deficit, federal budget uncertainty, fiscal policy, inflation, and Federal Reserve Board policies on interest rates. Investors generally have good information on the economic and financial variables outlined above. All of this information is available quickly, especially in recent decades with easy access to the internet.

Like the information available on the general economy, investors also have access to a wealth of information about particular types of securities, industries and specific company investments. This information is also factored into investor expectations and therefore the stock price individuals are willing to pay.

Common stock earnings growth rate forecasts and historical growth rate data may be found in the Value Line publication. These Value Line earnings estimates are five-year projections in annual earnings. Again, Value Line is widely available to the public and is a good source of earnings projections. Other earnings estimates are forecasted by Zacks, which are widely available on the internet at Zacks.com. Those earnings projections, along

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with other stock-specific financial data, provide a range of estimates of earnings and are readily available at no cost.

Another growth estimate is referred to as the sustainable growth or retention ratio growth estimate. To project future growth in earnings under the sustainable growth method, one multiplies the fraction of a firm's earnings expected to be retained (not paid out as dividends) by the expected return on book equity. As a formula:

Growth = ("b" x "r")

Where:
"b" =1- (dividends per share/earnings per share)
"r" =earnings per share / net book value share

All the data necessary to calculate the elements of the sustainable growth method are available on a forecasted basis in Value Line.

I have extended this sustainable growth formula to include the impact of external equity financing. The growth formula including external financing is:

$$g = br + sv$$

The terms "b" and "r" have been described above, and "s" is the expected growth in shares to finance investment, and "v" is the profitability of those expected investments.

Q. PLEASE EXPLAIN YOUR GROWTH RATE ANALYSIS.

A. I have included in my Exhibit (DJL-7), a three-page schedule showing the growth rates I have reviewed in my analysis. The first set of growth rates examined is the five-year and ten-year historical growth rates in earnings per share, dividends per share, and book value per share as reported by Value Line. The second set of growth rates are the Value Line forecasted growth rates in dividends, book value and earnings per share for each company in the comparable group. The third set of growth rates examined is the Zacks forecasted growth rates in earnings. The fourth growth estimate considered is the forecasted internal growth, the so-called sustainable growth estimate discussed above. The growth rates described above provide a range of estimates for each of the comparable companies. The resulting range of average and median forecasted growth rates for the electric utility comparable group is shown in Exhibit (DJL-7) at page 1 of 3.

Q. DID YOU RELY ON THE HISTORICAL GROWTH RATES?

A. No. Historical growth rates are a starting place for the analysis, but investors consider additional information when formulating expectations. Moreover, whether the trends of the past ten or five years continue to hold for the future is often a suspect assumption. Instead, for the constant growth DCF, I rely on the sustainable growth estimates as a predictor of investor expectations. I also employ the average of the Value Line, Zacks earnings estimates, and sustainable growth estimates in a second DCF model estimate and for the two-stage growth model to provide a range of estimates.

Q. PLEASE SUMMARIZE YOUR CONSTANT GROWTH DCF ANALYSIS.

A. The 14-company comparable group DCF employing sustainable growth estimates mean and median results fall in a range of 8.51% to 8.95% with an approximate 8.70% midpoint. These analyses can be found in my Exhibit (DJL-8), column I. The DCF employing earnings forecast and sustainable growth average mean and median results fall in a higher range of 9.6246% to 9.95% with an approximate 9.80% midpoint. These analyses can also be found in my Exhibit (DJL-8), column F.

Q. HAVE YOU CALCULATED ADDITIONAL DCF ANALYSES FOR THE COMPARABLE GROUP COMPANIES?

A. Yes. I have calculated a two-stage non-constant growth DCF analysis for the companies in the comparable group.

Q. PLEASE DESCRIBE YOUR TWO-STAGE NON-CONSTANT GROWTH DCF.

A. This analysis calculates equity cost using a two-stage non-constant growth DCF Model. The constant growth DCF model can be adjusted to reflect multiple growth assumptions because the constant growth rate assumption is often not consistent with investor expectations. As an example, it is often the case where short-term growth estimates are not consistent with long-term sustainable growth projections. In those instances, where more than one growth rate estimate is appropriate, a multi-stage non-constant growth model can be employed to derive a cost of capital estimate. In other words, the constant growth model is adjusted to incorporate multiple growth rate periods, assuring a constant growth (long-term) rate is estimated for a longer period.

For the comparable group, the first growth stage (years 1-5) of the model, the Value Line forecasted growth in dividends is employed, and an annual dividend is calculated. The second stage (years 6 and beyond) employs an earnings growth estimate based on the individual company in the comparable group of forecasted earnings per share Value Line, Zacks, and the forecast sustainable growth estimate ("b*r" + "s*v"). The estimated cash flows are modeled over an extended period and return is calculated employing the Internal Rate of Return formula ("IRR").

Q. WHAT ARE THE RESULTS OF THE TWO-STAGE NON-CONSTANT GROWTH DCF ANALYSIS?

A. The results of the two-stage non-constant growth DCF analysis for the utility group are shown in Exhibit (DJL-9), column K, lines 1 -14. The utility company comparable group mean and median results indicate a cost of equity range of 9.46% to 9.87% with a 9.65% midpoint.

VIII: BOND YIELD EQUITY RISK PREMIUM, CAPM, AND ECAPM COST OF EQUITY ESTIMATE

Q. PLEASE DESCRIBE THE RISK PREMIUM ANALYSIS.

A. Debt instruments such as bonds (long-term debt) are less risky than common equity when both classes of capital are issued by the same entity. Bondholders have a prior contractual claim to the earnings of the corporation and returns on bonds are less variable and more predictable than stocks. The bottom line is that debt is less risky than equity. There are numerous return studies of capital market investments, all of which show lower returns with lower risks and higher returns with higher risk investments. These financial truisms provide the theoretical basis and foundation for the risk premium method for estimating equity costs.

The risk premium approach is not without its problems and drawbacks. In practice and application, there is considerable debate as to the historical time period to analyze and added debate concerning the calculation of the bond/equity return risk spread. Historical debt/equity risk spreads measured over many decades may not be relevant to current capital market requirements. Others argue that a long-term analysis is necessary, since the goal is to measure investors' long-term expectations.

Another version of the risk premium method is the CAPM.

Finally, I examine ECAPM estimates. The ECAPM is quite similar to the CAPM described above with the difference being an adjustment for the beta estimate in the model. Firms with beta estimates below unity tend to have actual beta values that are higher. The ECAPM includes an adjustment to correct for any systematic measurement errors in beta.

CAPITAL ASSET PRICING MODEL ANALYSIS

Q. PLEASE EXPLAIN HOW YOU CALCULATED THE EQUITY RETURN ESTIMATE EMPLOYING THE CAPM.

A. I employed the basic CAPM formula denoted as follows:

$$R_f + \beta(R_m - R_f)$$

Where:

R_f = risk free rate;
β =beta;
R_m= market return; and
R_m - R_f= market risk premium or (“MRP”).

This is the typical model structure employed by most financial analysts in estimating equity returns.

Q. WHAT RISK FREE (R_f) VALUE DID YOU EMPLOY IN YOUR CAPM ESTIMATE?

A. I typically employ the most recent three-month average of the 30-Year U.S. Treasury Bond rates. This three-month average is:

Table 13[109]

30-Year U.S. Government Bond Yields

February 2025	4.68%
March 2025	4.60%
April 2025	4.71%
3-Month Average	4.66%

I have also employed a 4.25% range 30-Year U.S. Treasury Bond yield which is consistent with the market expectations of declining future rates as the Federal Reserve is expected to lower federal funds rates over the foreseeable future of the proposed 2026 - 2027 test year periods proposed in this case. Now, given the projections of federal funds rates to

[109] The monthly bond yields are presented in Exhibit (DJL-4).

reverse course and continue to decline, a 4.25% expectation for U.S. Treasury yields is reasonable.

Q. WHAT VALUE DID YOU EMPLOY FOR BETA IN YOUR CAPM ANALYSIS?

A. I employed a Value Line beta estimate for each company in the comparable group as shown in my Exhibit (DJL-5), column A into the CAPM Exhibit (DJL-10), columns A and E.

Q. WHAT VALUE HAVE YOU EMPLOYED FOR THE MARKET RISK PREMIUM?

A. To calculate the MRP, I estimated a more current regulated utility MRP calculation by measuring the difference between the authorized equity return for electric utilities and 30-year U.S. Treasury yields for the period 1981 through 2024.[110] This alternative produces an average risk premium for utility stocks of 5.45%. Translating this utility risk premium to a market risk premium I divide the 5.45% premium by the utility group midpoint beta of .875 and the imputed Market Risk Premium is 6.23%.[111] This 6.23% MRP estimate is consistent with the expected ranges of MRP of 5% - 8% found in a number of studies in the financial literature and is consistent with current financial markets expectations for MRP.[112]

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSES FOR THE ELECTRIC COMPANY COMPARABLE GROUP?

A. The results of the CAPM analyses can be found in my Exhibit (DJL-10) at column D for the electric comparable group. The range of results for the FPL proposed utility group indicate an equity return mean and median of 9.70% to 9.70% with a 9.70% midpoint.

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[110] See Exhibit (DJL-11) average historical (1981 - 1924) risk premium of 5.45%.
[111] Morin, Roger; New Regulatory Finance, Public Utility Reports, Inc. page 162 Implied Regulatory MRP's (2006).
[112] Morin, Roger; New Regulatory Finance, Public Utility Reports, Inc. (2006). See Chapter 5.

Q. IN YOUR ANALYSES, HAVE YOU INCLUDED A CALCULATION OF THE EMPIRICAL CAPM OR ECAPM RETURN ESTIMATE FOR THIS CASE?

A. Yes. Like the CAPM analysis discussed above, the ECAPM estimate of equity return relies on basic financial portfolio theory. To correct for the potential of biased beta estimates, an adjustment is made so as not to understate the cost of equity. The basic formula for the ECAPM for beta conversion is as follows:

$$K=R_f + 0.25(R_m - R_f) + 0.75\beta(R_m - R_f)$$

Q. WHAT ARE THE RESULTS OF YOUR ECAPM ANALYSES FOR THE ELECTRIC COMPANY COMPARABLE GROUP?

A. The results of the ECAPM analyses can be found in my Exhibit (DJL-10) at column H. The mean and median result of ECAPM results for the 14 - company proposed comparable group are 9.89% and 9.89% respectively, with a midpoint of 9.90%.

Q. DESCRIBE YOUR BOND YIELD EQUITY RISK PREMIUM ANALYSIS.

A. The bond yield equity risk premium analysis is presented in Exhibit (DJL-11) and evaluates the risk/return differential between the authorized electric utility return on equity relative to 30-year U.S. Treasury bond yields for the period 1981-2024. The resulting risk premium is combined with the estimated 30-year U.S. Treasury yield of 4.66% and the forecast estimate of 4.25% to determine the range of risk premium estimates of equity costs.

The resulting risk premium range of results for the utility group is 10.39% to 10.64% with a 10.52% midpoint estimate. These risk premium results exceed all other model results and were not considered in the final analysis.

Q. PLEASE SUMMARIZE YOUR COST OF EQUITY CAPITAL RESULTS AND RECOMMENDATION.

A. Table 14 below is a summary of all the equity cost estimates for the comparable group companies employing the constant growth DCF, 2-Stage DCF, CAPM, ECAPM, and Risk Premium models.

Table 14

Cost of Equity Estimates Employing FPL Comparable Risk Group[113]

MODEL	RANGE LOW - HIGH	MIDPOINT	Summary averages of midpoints
DCF Model (Average Growth)[114]	9.62% - 9.95%	9.80%	
DCF Model (Sustainable Growth)	8.51% - 8.95%	8.70%	
Two-stage DCF	9.46% - 9.87%	9.65%	3 – DCF Models 9.4%
CAPM	9.70% - 9.70%	9.70%	
ECAPM	9.89% - 9.89%	9.90%	CAPM & ECAPM 9.8%
Risk Premium	10.39% - 10.64%	10.50%	
Average of all Models (Rounded) Average of all models (excluding risk premium)	9.60% - 9.83% 9.44% - 9.67%	9.70% 9.55%	9.7% 9.6%
Minimum Maximum		8.51% 10.39%	
Reasonable Range	9.40% - 9.80%	9.60%	9.60%
Financial Risk adjustment[115]		-.40%	-.40%
Recommended equity return		9.20%	9.20%

[113] Each cost of equity capital estimate is discussed in the testimony and is presented in Exhibits (DJL-8), (DJL-9), (DJL-10), (DJL-11), and (DJL-13).
[114] Discounted Cash Flow ("DCF").
[115] The 40-basis point downward risk adjustment can be found in Section IX "Capital Structure".

The results of the analyses shown in Tables 14 are relatively close. I recommend a final range of 9.40% - 9.80% with a midpoint of 9.60%. Adjusting the range downward by 40 basis points for financial risk results in a risk adjusted equity return of 9.20%.

Q. IN YOUR OPINION WILL FPL MAINTAIN ITS FINANCIAL INTEGRITY WITH A 9.20% EQUITY RETURN.

A. Yes. Reviewing the impact of a reduction in return from the current 10.80% authorized midpoint ROE to a 9.20% level is about $600 million in return dollars and cash flow annually. The $600 million ROE reduction impact on the Standard & Poor's financial metric, Funds From Operations to Debt percentage (FFO/Debt%), is not likely to reduce or materially weaken this FFO/Debt% metric which is consistently well above 19%.

IX: CAPITAL STRUCTURE

Q. WHAT CAPITAL STRUCTURE IS FPL REQUESTING AS PART OF THIS PROCEEDING?

A. Based on the direct testimony of Company witness Scott Bores, the Company is requesting that the Commission approve the continuation of the Company's regulatory capital structure that is based on a 59.6% equity ratio from investor sources and a 50.07% equity ratio based on all regulatory sources for the 2026 test year.[116] Mr. Bores goes on to point out that "FPL has maintained a consistent equity ratio level for the past quarter century, and it has been fundamental to the overall financial strength that has served customers well."[117] Mr. Bores then states "the capital structure has a direct impact on financial strength and credit quality."[118] I agree it does have an impact on credit quality and it also

[116] Direct testimony Scott Bores at page 47, lines 12 - 14.
[117] Direct testimony Scott Bores at page 47, lines 14 - 16.
[118] Direct testimony Scott Bores at page 47, lines 16 - 17.

impacts customer rates. However, he never addresses the question of where credit quality is synonymous with a high equity ratio; how much credit quality does FPL need? Or put another way how much credit quality can customers afford and have reasonable electric rates? Mr. Bores may have provided an answer to these questions in his next sentence where he states, "[a] greater equity component means safer returns for **debt investors**, which translates to stronger credit ratings and lower borrowing costs."[119]

Based on Mr. Bores analysis, the FPL customers benefit from paying higher rates to support a 59.60% equity ratio because borrowing costs will be lower. Given that I employed Duke Florida as an example earlier to show how the Duke 53% equity ratio benefits customers, I further examined the Duke Florida stated borrowing cost for long-term debt for the proposed test years 2025 and 2026. The Duke Florida borrowing cost (long-term debt cost) was reported as 4.49% for 2025 and 4.52% for 2026.[120] In this case, FPL's long-term debt cost for 2025 and 2026 test year is 4.52% and 4.64%, respectively, which is higher than Duke Florida.[121] It does not appear FPL customers are getting a lot of bang for the buck in paying for the additional equity in the capital structure - they also get to pay higher interest costs as well.

Included in Tables 15 and 16 is a summary of each class of capital for each of the two test years of the multi-year rate plan as proposed by FPL.

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[119] Direct testimony Scott Bores at page 47, lines 17 - 19.
[120] See Docket No.20240025-EI MFR Schedule D-1a, at pages 2 and 3 of 5.
[121] Company MFR D-1a 2025 Test Year and 2026 Test Year.

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Table 15

Requested Capital Structure and Cost Rates for

FPL Operations Rate Year 2026[122]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.07%	11.90%	5.9583%
LONG-TERM DEBT	32.65%	4.64%	1.51496%
SHORT-TERM DEBT	1.30%	3.80%	0.0494%
CUSTOMER DEPOSITS	0.82%	2.15%	0.01763%
DEFERRED INCOME TAXES	10.96%	0.00%	0.00%
FAS 109 DEFERRED TAXES	3.20%	0.00%	0.00%
INVESTMENT TAX CREDITS	1.00%	9.03%	0.0903%
TOTAL CAPITAL	100.00%		7.63%

Table 16

Requested Capital Structure and Cost Rates for

FPL Operations Rate Year 2027[123]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.12%	11.90%	5.9643%
LONG-TERM DEBT	32.55%	4.69%	1.52659%
SHORT-TERM DEBT	1.42%	3.79%	.053818%
CUSTOMER DEPOSITS	0.81%	2.15%	0.017415%
DEFERRED INCOME TAXES	11.21%	0.00%	0.00%
FAS 109 DEFERRED TAXES	2.99%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.90%	9.06%	.08154%
TOTAL CAPITAL	100.00%		7.64%

[122] Capital structure and cost rates per Company filing MFR D-1a 2026 Test Year.
[123] Capital structure and cost rates Company filing MFR D-1a, 2027 Test Year.

As shown in the Tables, the capital structure has slight variations each year, but does remain relatively constant. The largest percentage change is the increase in 2027 short-term debt reflecting financing capital additions in 2026 and 2027.

Q. DO YOU AGREE WITH FPL'S CAPITAL STRUCTURE REQUEST?

A. No. I disagree with FPL's requested capital structure as proposed by Company witnesses Scott Bores and James M. Coyne. In this proceeding, FPL is asking the Commission to approve a capital structure that includes an equity ratio of 59.60%. I have addressed the problems and costs associated with the 59.60% equity ratio – FPL's request in this case. Customers would be better off with a lower equity ratio in capital structure.

Q. DO YOU HAVE COMMENTS AND RECOMMENDATIONS ON THE COMPANY'S PROPOSED CAPITAL STRUCTURE RATIOS FOR DEBT AND EQUITY?

A. Yes, I do. Rather than directly adjust the capital structure by reducing the equity ratio, I am proposing to adjust the equity return downward as calculated in the discussion below. This way, the Company can address the capital structure issue over time so as to not disturb financing of the ongoing capital projects. It would be my recommendation that the 59.60% equity ratio be reduced to or around the average utility by the time of the next rate proceeding (assuming the 4-year rate plan is approved).

Q. HOW SHOULD THE COMPANY'S PROPOSED CAPITAL STRUCTURE WITH A 59.60% EQUITY RATIO BE ACCOUNTED FOR TO ADDRESS THE LOWER FINANCIAL RISK OF THE COMPANY RELATIVE TO THE COMPARABLE RISK GROUP?

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A. It is a fundamental truism of finance that as a firm increases the relative amount of debt capital in the capital structure, total fixed charges (interest) increase the fixed obligations of the firm. The resulting residual earnings available to equity become subject to increased volatility and risk as leverage and fixed obligations increase. It is important to note that the average of the comparable risk company group has about a 51.80% equity ratio which would be more-risky (in terms of financial risk) than the FPL 59.60% equity ratio.[124] As such, the equity return estimates developed from the comparable group would reflect higher financial risk and would need to be reduced if applied to FPL with a 59.60% equity ratio for setting rates in this case. Mr. Coyne's analysis fails to recognize the financial risk differences between FPL and the comparable group.

Q. DOES THIS COMMISSION RECOGNIZE THAT FINANCIAL RISK ADJUSTMENTS ARE NECESSARY FOR DIFFERENT LEVELS OF EQUITY IN CAPITAL STRUCTURE?

A. Yes. For example, in Docket No. 20250006-WS, the Commission addressed the water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities.[125] In that proceeding, the Commission established an equity return range of 8.51% equity return for water and wastewater operations with 100 percent equity in capital structure.[126] On the other end of the spectrum, an equity return of 10.51% was established for water and wastewater operations with a 40% equity return. For those water and wastewater operations in between the following equity return leverage

[124] See FPL witness Coyne direct testimony at Exhibit JMC-11 page 2 of 6.

[125] See Docket No. 20250006-WS Water and wastewater industry annual reestablishment range of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S. Memorandum (May 21, 2025) at 1.

[126] See Docket No. 20250006-WS Water and wastewater industry annual reestablishment range of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S. Memorandum (May 21, 2025) at 3.

formula was developed.[127]

ROE= 7.17% + (1.337/ (equity ratio)[128]

This leverage formula recognizes that the higher equity ratio levels in the capital structure results in lower equity returns due to lower financial risks. This is what my proposed financial risk adjustment to lower the ROE due to the high equity ratio addresses in this case.

Q. CAN YOU POINT TO STUDIES IN THE FINANCIAL LITERATURE THAT EVALUATE THE IMPACT OF INCREASED FINANCIAL LEVERAGE IN THE CAPITAL STRUCTURE AND EQUITY COST?

A. Yes. There are a number of studies in the financial literature, both empirically and theoretically based, that attempt to quantify the effects of leverage on the common equity costs.[129] These studies suggest an increase in common equity costs in a range of 7.6 basis points on the low end to 13.8 basis points on the high end for every 100 basis point increase in the debt ratio within the 40% to 50% range of leverage. [130] Thus, on average, there is about a 10.7 basis point increase [(7.6% + 13.8%)/2] in equity cost for every 100-basis point change in debt in capital structure.[131]

Q. PLEASE DESCRIBE THE FINANCIAL RISK ADJUSTMENT TO ADJUST FOR FPL'S LOWER FINANCIAL RISK VERSUS THE COMPARABLE GROUP'S

---

[127] See Docket No. 20250006-WS Water and wastewater industry annual reestablishment range of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S. Memorandum (May 21, 2025) at 3.
[128] See Docket No. 20250006-WS Water and wastewater industry annual reestablishment range of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S. Memorandum (May 21, 2025) at 3.
[129] See Morin, Roger: New Regulatory Finance, Public Utility Reports, 2006, at 468 - 469.
[130] *Id.*
[131] *Id.*

FINANCIAL RISK.

A. The FPL 59.60% equity level substantially exceeds the comparable group equity average, thus FPL's financial risks are less than the comparable group. Given the Company's data in Exhibit JMC-11 at page 2 of 6, I have estimated the comparable group equity ratio based on the median estimates to be 51.8% which is 7.8 percentage point difference (59.6% - 51.8%) in equity in capital structure. Given that the Company has been authorized a 59.6% equity ratio for a number of years (25-years according to Mr. Bores), I approach this adjustment with gradualism in mind and only adjust half of the 7.8 percentage point differential or 3.9 percentage points. Thus, I calculate the risk adjustment assuming the Company should be authorized a 55.7% equity ratio for this case. A financial risk adjustment translates into an average of 41.7 basis points (3.9 percentage points x 10.7 average level of basis points)[132] equity return reduction for FPL relative to the comparable group results. I have reduced the equity return range recommendation identified in Table 1 and Table 14 of 9.60% down by 40-basis points to 9.20%. Considering the results of the range, a point estimate of 9.20% reflects FPL's lower financial risk given 59.60% equity in the capital structure versus the comparable group's 51.8% average equity ratio.

Q. WHAT CAPITAL STRUCTURE AND COST RATES ARE YOU RECOMMENDING THAT THE COMMISSION ADOPT IN THIS CASE?

A. Based on the analyses and results discussed above, I am recommending a capital structure employing FPL's proposed capital levels and cost rates except that the equity return should be set at 9.20%. The capital structure and cost rates are set forth in the following tables:

[132] This calculation conservatively employs the lower end and average of the 7.6 to 10.7 basis point adjustment range discussed above.

Table 17

Recommended Capital Structure and Cost Rates for FPL Operations Rate Year 2026[133]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.07%	9.20%	4.61%
LONG-TERM DEBT	32.65%	4.64%	1.51%
SHORT-TERM DEBT	1.30%	3.80%	0.05%
CUSTOMER DEPOSITS	0.82%	2.15%	0.02%
DEFERRED INCOME TAXES	10.96%	0.00%	0.00%
FAS 109 DEFERRED TAXES	3.20%	0.00%	0.00%
INVESTMENT TAX CREDITS	1.00%	7.4%	0.07%
TOTAL CAPITAL	100.00%		6.26%

Table 18

Recommended Capital Structure and Cost Rates for FPL Operations Rate Year 2027[134]

DESCRIPTION	RATIO	COST	WEIGHTED COST
COMMON EQUITY	50.12%	9.20%	4.61%
LONG-TERM DEBT	32.55%	4.69%	1.53%
SHORT-TERM DEBT	1.42%	3.279%	.05%
CUSTOMER DEPOSITS	0.81%	2.15%	0.02%
DEFERRED INCOME TAXES	11.21%	0.00%	0.00%
FAS 109 DEFERRED TAXES	2.99%	0.00%	0.00%
INVESTMENT TAX CREDITS	0.90%	7.42%	.08%
TOTAL CAPITAL	100.00%		6.29%

[133] Capital structure and cost rates (except equity cost and ITC cost) per Company filing MFR D-1a, page 3 of 5. Equity cost of 9.20% per this testimony and ITC cost based on the adjusted composite long-term debt and equity cost. Of course, if there any specific dollar adjustments to the Company's amounts for any source of capital before the capital structure is reconciled to rate base, there would be corresponding effects.

[134] Capital structure and cost rates (except equity cost and ITC cost) per Company filing MFR D-1a, page 3 of 5. Equity cost of 9.20% per this testimony and ITC cost based on the adjusted composite long-term debt and equity cost. Of course, if there any specific dollar adjustments to the Company's amounts for any source of capital before the capital structure is reconciled to rate base, there would be corresponding effects.

Thus, the recommended overall cost of capital for the 2026 test year is 6.26% and includes a 9.20% equity cost. The recommended overall cost of capital for the 2027 test year is 6.29% and includes a 9.20% equity cost.

As can be seen from the above table, when the common equity cost rates reflect current market conditions and risks, the final recommended Company's overall cost of capital is substantially lower than the FPL request for each year for the rate plan. I have included the capital structure, cost rates, and expected revenue impacts in my Exhibit (DJL-12).

X: RESPONSIVE TESTIMONY TO COST OF CAPITAL WITNESS MR. JAMES COYNE

Q. DO YOU HAVE ANY COMMENTS REGARDING THE DIRECT TESTIMONY AND RECOMMENDATIONS OF COMPANY WITNESS JAMES COYNE?

A. Yes, I have a number of comments. First, regarding Mr. Coyne's recommended return on equity of 11.90% for FPL, such a return level is overstated and not supported by market data.[135] Mr. Coyne's 11.90% ROE recommendation appears to be based on his range of 10.28% to 15.65% from the extreme ends of his model results rather than current and/or expected market conditions, business or financial risk considerations, or other specific risk considerations. As I discussed earlier in this testimony, current market data supports a lower equity return. Further, in light of average authorized returns in the country are under 10.00%, Mr. Coyne's proposed the 11.90% equity return is absurdly high. FPL should not have a higher return than comparable risk companies. FPL should have a comparable ROE

[135] Direct Testimony Mr. Coyne at page 44, Figure 16, and page 61, lines 9 - 11.

based on market conditions and risks, no more and no less.[136] There is no evidence that suggests FPL's Florida operations are more-risky than the average electric utility in this country. One must believe either FPL is riskier than the average utility or every other regulatory Commission is wrong and substantially understating utility cost of equity requirements. Obviously, FPL is not riskier than the average utility and all other regulatory authorities have not set equity returns incorrectly. Instead, Mr. Coyne is taking an unreasonable position, and his 11.90% equity return is not supported. On this basis alone, Mr. Coyne's recommendation makes no sense. Moreover, when you consider the risk reducing benefits of Florida rate mechanisms and the benefits of the negotiated multi-year rate plans of the past, along with the proposed multi-year rate plan (if approved over OPC objection), FPL is less risky.

Q. HOW DID MR. COYNE ARRIVE AT SUCH A HIGH END EQUITY RETURN RECOMMENDATION?

A. Mr. Coyne ran four common financial models to estimate the equity return in this case. The results of his analysis are summarized in the following Table 19:

TABLE 19[137]

EQUITY RETURN MODEL SUMMARY BY FPL WITNESS MR. COYNE

MODEL	ROE RESULTS EMPLOYING CURRENT INTEREST RATES	ROE RESULTS EMPLOYING PROJECTED INTEREST RATES
DCF	10.28%	10.28%
CAPM	15.65%	15.63%
RISK PREMIUM	10.57%	10.45%
EXPECTED EARNINGS	10.91%	10.91%
AVERAGE ROE	11.85%	11.82%
AVERAGE EXCLUDING CAPM[138]	10.58%	10.55%

[136] Direct Testimony Mr. Coyne at Exhibit JMC-6, page 4 column 1. Also, see Exhibit (DJL-11) which shows annual average authorized returns.
[137] See Direct testimony James Coyne at page 44 Figure 16.
[138] Average Excluding the CAPM result is calculated by Mr. Lawton and is not part of Mr. Coyne's written testimony.

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Mr. Coyne then adds 9-basis point for flotation costs to the 11.83% average produced by the models [(11.82% + 11.85%)/ 2) = 11.83%] and rounds the sum to 11.90% to arrive at his recommendation.

The obvious problem with Mr. Coyne's analysis, is the 15.6% outlier calculated for the CAPM. As I show in Table 19, if you calculate the average without the CAPM outlier, the recommendation falls by about 120-basis points. This failure to recognize this outlier problem ends up contributing over $500 million per year to the proposed annual rate increase for customers in this case.[139]

An analyst should not leave reason at the doorstep and not question his modeling efforts especially when they are facially absurd like the CAPM. Had Mr. Coyne checked his own testimony at Exhibit (JMC-6) column 1, he would have realized that the highest average equity returns authorized by regulatory authorities around the country were in the third quarter of 1994 at 12.75%. Now 31 years later when capital costs are much lower than historical levels, Mr. Coyne believes a 15.65% estimate is reasonable. The consequences of his casual approach is over $500 million in added annual rate request by his client FPL to be imposed on customers. The Commission should give little weight to Mr. Coyne's proposal.

Q. HAVE REGULATORY COMMISSION'S RECENTLY QUESTIONED THE REASONABLENESS OF THE CAPM APPROACH?

A. Yes. In a recent Nevada Power Company case, the Public Utilities Commission of Nevada found that "the CAPM and ECAPM analyses should be viewed with some caution."[140] In

[139] See Exhibit (DJL-12) notes.
[140] Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers, Before the Public Utilities Commission of Nevada Docket No. 23-06007 (Modified Final Order) at page 34, paragraph 85 (February 13, 2024).

that proceeding, the Nevada Commission was addressing sensitivity to changes in Treasury yields. This example points out that all analyses must be evaluated for reasonableness. I should also note that including the CAPM in an average with other model results does not cure the reasonableness problem. Instead, you end up with an unreasonable average as evidenced by the over $500 million rate impact of this one model result on consumers.

Q. DO YOU HAVE ANY COMMENTS REGARDING THE MR COYNE'S DCF ANALYSIS?

A. Yes, Mr. Coyne's DCF analysis results for his 15-company comparable group are presented in his Exhibit JMC- 4, consisting of three pages. Mr. Coyne relied only on the average results of the 30-day, 60-day, and 90-day dividend yield periods to get an overall 10.28% for the DCF model. Had he considered the low growth DCF results given the potential for a slower growing economy, his low results indicate a 9.05% equity return.[141] This low growth result of 9.05% equity return is in line with my recommendation in this case.

Q. DO YOU HAVE ANY ADDITIONAL COMMENTS REGARDING MR. COYNE'S CAPITAL ASSET PRICING MODEL ESTIMATES?

A. Yes, I do. I have already addressed the overall issue regarding the reasonableness of Mr. Coyne's CAPM analysis. The major problem with Mr. Coyne's CAPM calculations is his use of an overstated market risk premium. His end result is an equity return recommendation that is unreasonable in and of itself.

The second problem with the CAPM estimates is that Mr. Coyne's estimate of the market return for estimating the market risk premium is based on constant growth DCF for

[141] Direct testimony James Coyne at EXHIBIT (JMC-4) Column 9 average at pages 1, 2, and 3.

expected **returns of the dividend paying stocks** and **non-dividend paying growth stocks** in the S&P 500.[142] One should be cautious trying to apply a discounted cash flow analysis to non-dividend paying growth stocks – as it can lead to absurd results.[143] As I discussed in the CAPM section of this testimony, a fair analysis of market risk premiums suggests a much lower risk premium.

Q. DID MR. COYNE DEVELOP OTHER EQUITY RETURN MODELS FOR HIS ANALYSES?

A. Yes, Mr. Coyne developed a risk premium analysis producing a 10.45% to 10.57% equity return estimate.[144] These estimates are consistent with my own estimates discussed above. In addition, Mr. Coyne developed an Expected Earnings model that produced a mean return of 10.91% and a median return of 10.27%.[145] However, when evaluating the final model results, Mr. Coyne ignored his lower 10.27% model median estimate and relied solely on the much higher 10.91% mean.[146]

It seems that Mr. Coyne's analysis is not balanced, and that all his adjustments from evaluating the CAPM, ignoring the lower end DCF results, and selecting the highest midpoint in the expected earnings analysis are skewed to pick the highest results. The Commission should not consider results that do not reflect a balanced and fair weighing of such results. For these reasons, I recommend that the Commission give Mr. Coyne's proposals little weight.

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[142] Direct Testimony Mr. Coyne at page 38, lines 18 - 19 and at Exhibit No. JMC - 5.
[143] See Morin, Roger: New Regulatory Finance, Public Utility Reports, 2006, at page 255.
[144] See Direct testimony James Coyne at page 42, Figure 15.
[145] See Direct testimony James Coyne at page 43, lines 10 - 11.
[146] See Direct testimony James Coyne at page 44, Figure 16.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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ERRATA SHEET

Witness: Daniel J. Lawton

Please note the following ERRATA in direct testimony:

Page	**Line**	**As Filed**	**Correction**
Page 5	Table 1, Line 3 "Two-stage DCF"	RANGE LOW-HIGH "9.46% - 9.87%" MIDPOINT "9.66%"	RANGE LOW-HIGH "9.53% - 9.84%" MIDPOINT "9.68%"
Page 47	Line 1	Strike "9.46% to 9.87% with a 9.65% midpoint"	Replace with "9.53% - 9.84% with a 9.68% midpoint"
Page 51	Table 14, Line 3 "Two-stage DCF"	RANGE LOW-HIGH "9.46% - 9.87%" MIDPOINT "9.65%"	RANGE LOW-HIGH "9.53% - 9.84%" MIDPOINT "9.68%"
Page 56	Line 20	Strike "return"	Replace with "ratio"

C22-3284a

BY MS. CHRISTENSEN:

Q Mr. Lawton --

A Yes.

Q -- did you prefile in this docket exhibits labeled DJL-1 through DJL-13?

A I did.

Q And do you have any corrections to those prefiled exhibit?

A Like the direct testimony, there was an errata filed in the papers in this cause for some of the exhibits.

Q Okay. And other than the corrects that were contained within the prefiled errata, do you have any additional corrections as we stand here today?

A I do not.

Q Okay. Mr. Lawton, did you prepare a summary of your testimony?

A I am sorry, I didn't hear that.

Q Certainly. Did you prepare a summary of your testimony?

A I did.

Q I would ask that you share that summary with us today.

A Sure. Sure.

Good afternoon, Commissioners. I am Dan

Lawton. I am an economist. And the issue I address in this proceeding is that age old issue of cost of capital, or shareholder profit, capital structure, and the cost rates of the various components of the capital structure.

And in this case, the current authorized return by this commission is currently 10.8 percent profit for shareholders. In this case, the company is requesting 11.9 percent return on equity.

Now, the difference between your current 10.8 percent authorized return and this 11.9 percent request is 110 basis points, but put that aside. What does it come down to? It comes down to cash. That's a $554 million more per year for shareholders. That's one-third of the entire 1.3 billion rate increase. And over the four years of the rate plan, that would turn into 2.2 billion additional dollars for shareholders at the expense of all Florida ratepayers.

Now, the first issue that I address -- well, first of all, how did he -- the company come up with 11.9 percent? Is this the interesting part. They had Mr. Coyne do an analysis on cost of equity. He used standard models accepted by commissions around the country, some of the same models I use, but his results of three of the models were between 10.3 percent return and 10.9 percent return. Fairly consistent with your current authorized 10.8 percent. But one model, the capital asset pricing model, came up to an astounding 15.6 percent. So what did Mr. Coyne do? He averaged them together, and he came up with his 11.9 percent. He added in some floatation costs, nine basis points.

So that difference of $555 million per year is based upon one model that comes up to 15.65 percent. There is not a commission in this country that has authorized a return that high on average. And you can look at Mr. Coyne's own data in his testimony, and the highest return goes back to, I think, 12.34 percent in one of his exhibits, yet Mr. Coyne used it. And what did the use of that capital asset pricing model do? It drove the return on equity requests 110 basis points, or $555 million.

Now, I did an alternative analysis employing the same -- similar models. I came up with a range of, reasonable range, of 9.4 to 9.8 percent. That means a midpoint of about 9.6 percent. I reduced it by 40 basis points down to 9.2 percent because of the 59.6 percent equity ratio and capital structure. And that is my recommendation.

And I would ask that you give little weight to FPL's witness on this one. It's just no basis to come up with a 15.6 percent return on equity, and ask ratepayers to pay $555 million more per year.

Thank you.

MS. CHRISTENSEN: We tender Mr. Lawton for cross-examination.

CHAIRMAN LA ROSA: Thank you.

FEL?

MS. McMANAMON: No questions.

CHAIRMAN LA ROSA: FAIR?

MR. SCHEF WRIGHT: No questions. Thank you.

CHAIRMAN LA ROSA: FEIA?

MR. MAY: No questions.

CHAIRMAN LA ROSA: Walmart?

MS. EATON: No questions.

CHAIRMAN LA ROSA: FRF?

MR. BREW: No questions.

CHAIRMAN LA ROSA: FIPUG?

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FPL?

MR. BURNETT: No questions.

CHAIRMAN LA ROSA: Staff?

MR. SPARKS: Just a couple of questions, Mr. Chair.

CHAIRMAN LA ROSA: Sure.

MR. SPARKS: Thank you.

EXAMINATION

BY MR. SPARKS:

Q Good afternoon, Mr. Lawton.

A Good afternoon. Could you raise your hand? I can't see which one is talking.

Q Me.

A Oh, thank you. I am optically challenged, sir.

Q No problem.

Are you familiar with FPL's RSAM and TAM provisions?

A I am, indeed.

Q Do the RSAM and TAM stabilize FPL's earned return on equity?

A No. They inflate it and exaggerate it.

Q Is it generally accepted that variability of earnings is a measure of business risk?

A It is. Their ROE on equity, if you earn it every year, you don't have much business risk.

Q So in your opinion, would a reduction in the variability and earned return on equity reduce FPL's business risk?

A It would, but you are talking about the RSAM and additional the TAM, and think about what you are asking.

What FPL does, it uses the RSAM historically to raise the return up to and including the midpoint, which was authorized by this commission, and then they go beyond that another hundred basis points to the high end of the return range. Why in heavens name would anybody be allowed to do that? That has nothing to do with the risk. The risk is tied to the authorized return. Does FPL earn it every year? And the answer is yes.

Q So in your opinion, should a reduction in business risk have a commensurate reduction in allowed return on equity?

A Yes.

Q Thank you, those are all my questions.

CHAIRMAN LA ROSA: Thank you.

Commissioners, any questions?

Seeing no questions, back to OPC for redirect.

MS. CHRISTENSEN: No redirect.

CHAIRMAN LA ROSA: Awesome. Okay. Would you like to enter anything into the record?

MS. CHRISTENSEN: Yes. We would ask that Mr. Lawton's Exhibits 171 through 183 be moved into the record, including the erratas.

CHAIRMAN LA ROSA: Assuming no objections. Seeing none, so moved.

(Whereupon, Exhibit Nos. 171-183 were received into evidence.)

CHAIRMAN LA ROSA: Anything else that needs to be moved into the record?

MS. CHRISTENSEN: No, but we would ask Mr. Lawton be excused.

CHAIRMAN LA ROSA: Yes.

Mr. Lawton, you are excused. Thank you very much for joining us.

THE WITNESS: Thank you, Commissioners. Have a great day.

CHAIRMAN LA ROSA: Thank you.

(Witness excused.)

CHAIRMAN LA ROSA: I will allow OPC to call their next witness when they are ready.

MR. PONCE: Yes. OPC would call Mr. Thomas to the stand.

CHAIRMAN LA ROSA: Great, thank you.

Mr. Thomas, thank you for standing. Please raise your right hand, as you have done.

Whereupon,

JACOB M. THOMAS

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth, was examined and testified as follows:

THE WITNESS: Yes.

CHAIRMAN LA ROSA: Excellent. Thank you.

EXAMINATION

BY MR. PONCE:

Q Good afternoon.

A Good afternoon.

Q If you could please state your full name, and spell your last name for the record?

A Yes. My name is Jacob M. Thomas, T-H-O-M-A-S.

Q What is your business address?

A 1850 Parkway Place, Suite 800, Marietta, Georgia.

Q Did cause to be filed prefiled direct testimony in this docket on June 9, 2025?

A Yes.

Q Do you have any corrections for your prefiled testimony?

A No.

Q So if I were to ask you the same questions today as are contained in your testimony, would your answers be the same?

A Yes.

MR. PONCE: Mr. Chair, I would ask that Mr. Thomas' testimony be entered into the record as though read.

CHAIRMAN LA ROSA: So moved.

(Whereupon, prefiled direct testimony of Jacob M. Thomas was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re.: Petition for rate increase by Florida Power & Light Company.
________________________________/

Docket No. 20250011-EI

Filed: June 9, 2025

DIRECT TESTIMONY

OF

JACOB M. THOMAS, P.E.,

ON BEHALF OF

THE CITIZENS OF THE STATE OF FLORIDA

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EXHIBITS

C24-3830

DIRECT TESTIMONY OF

JACOB M. THOMAS, P.E.

On behalf of the Office of the Public Counsel

Before the

Florida Public Service Commission

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob M. Thomas. I am a Principal of GDS Associates, Inc. ("GDS"). My business address is 1850 Parkway Place, Suite 800, Marietta, GA 30067.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying in this proceeding on behalf of the Florida Office of Public Counsel ("OPC").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND QUALIFICATIONS.

A. I received a Bachelor of Science in Industrial and Systems Engineering from the Georgia Institute of Technology in 2000. I received a Master's of Business Administration with a concentration in Finance from Auburn University in 2006. I am a registered Professional Engineer in Georgia and a member of the American Statistical Association.

C24-3831

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I began working with GDS in June 1996 as a cooperative student while attending the Georgia Institute of Technology. After graduation in December 2000, I accepted a full-time position in GDS's Distribution Services department and have risen to my current position of Principal in that department. In the past 25+ years, I have provided financial, statistical, and economic consulting to utilities and regulatory agencies nationwide.

In the areas of finance and economics, I specialize in retail and wholesale cost-of-service development and design, retail and wholesale rate design, financial forecasting, economic impact analysis, and benefit-cost analysis of demand response programs. In the area of statistics, I have provided services to clients with respect to load forecasting, market research, sample design, load research, measurement and verification, and other statistical modeling.

Q. HAVE YOU TESTIFIED BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION BEFORE?

A. No, I have not.

Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?

A. Yes, I have provided expert testimony in the areas of cost of service, retail and wholesale rate design, load forecasting, and load research in several jurisdictions. I have testified in Georgia, Indiana, Maryland, Michigan, North Carolina, South Carolina, Utah, and Vermont. I have also filed testimony before the Federal Energy

Regulatory Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have reviewed Florida Power & Light Company's ("FPL") load and revenue forecasts as filed in this Docket. I recommend several adjustments to the load forecast which, in turn, impact present rate revenues.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring four exhibits.

- Exhibit JMT-1 is my professional resume.
- Exhibit JMT-2 is a summary of my recommended adjustments to the class customer and energy sales forecasts.
- Exhibit JMT-3 provides a summary of my recommended adjustments to present rate revenues in 2026 and 2027.
- Exhibit JMT-4 is a composite exhibit of select discovery responses.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION?

A. Yes.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. The remainder of my testimony is organized into the following sections:

II. Load Forecast Adjustments

II.A Customers

II.B Energy Sales

II.C Demand

III. Present Rate Revenue Adjustments

IV. Summary of Recommendations and Conclusion

II. LOAD FORECAST ADJUSTMENTS

II.A Customers

Q. PLEASE PROVIDE AN OVERVIEW OF FPL'S LOAD FORECASTING PROCESS.

A. FPL deploys a series of statistical models to project number of customers and usage per day ("UPD") per customer, based on billing days. Such pairs of models are prepared for each of six revenue classes. The UPD projections and customer projections are then multiplied to produce energy sales forecasts by revenue class. Peak demands are also estimated using regression model specifications. FPL develops separate models for its two regions, hereinafter referenced as the "FPLE" and "NWFL" regions. In general, FPL uses econometric modeling techniques, in which economic activity and associated economic projections are one of the key independent variables used to project customer and energy sales growth and uses a 20-year average of weather data to represent normal weather.

Q. DO YOU HAVE ANY CONCERNS ABOUT THE RESIDENTIAL CUSTOMER FORECAST?

A. I have concluded that the residential customer forecast is currently too low and should be adjusted upward for purposes of this proceeding. Analysis of the forecast performance relative to actual for the period for which actual data is available shows a consistent pattern of under forecasting actual number of customers:

Table 1: Residential Customer Forecast vs. Actual[1]

Date	RES Fcst	Actual	Difference
Jul-24	5,291,268	5,295,609	-4,341
Aug-24	5,297,025	5,303,897	-6,872
Sep-24	5,302,792	5,312,291	-9,499
Oct-24	5,308,551	5,318,891	-10,340
Nov-24	5,314,294	5,324,294	-10,000
Dec-24	5,320,004	5,329,908	-9,904
Jan-25	5,325,685	5,336,096	-10,411
Feb-25	5,331,345	5,344,332	-12,987

Although the magnitude of the errors may seem small now, the trend is likely to continue with the forecast getting less accurate through 2027. This is because the number of customers is a time series that exhibits very strong first order autocorrelation. First order autocorrelation exists when the value of the variable, in this case number of residential customers, is highly dependent on the value in the prior period. Because the number of customers is a running tally, first order autocorrelation is obvious. One challenge with forecasting a time series with such autocorrelation is

[1] FPL response to Staff 1st Set of Interrogatories, No. 6, represents the sum of information provided in Exhibit JMT-4 page 2 and JMT-4 page 8.

that a forecast that is under-forecasting is likely to continue to be too low. In order for the forecast to "catch up", actual growth would have to drop below forecasted growth rate because the forecast is already too low. This seems unlikely even if there are signs of less growth in Florida than recent years. As can be seen in Table 2, the forecast has produced lower growth rates for 2025-2027 than what was experienced over the last five years. If you extend the trend in number of customers the forecast is below actual, the error reaches 0.8% by the end of 2027 and represents nearly 45,000 fewer customers. In fact, the trend in Table 1 is so strong that a simple trend line regression gives a trend variable with a p-value of 0.003, which is very significant.

Table 2: Growth Rates of Past 5 Years and Forecast Period for Residential Customers

Region	Growth in Customers 2020-2025 (CAGR)	Projected Growth Rate 2025-2027 (CAGR)
FLPE	1.46%/yr	1.21%/yr
NWFL	1.50%/yr	1.29%/yr

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RESIDENTIAL CUSTOMER FORECAST?

A. Given what we know about actual residential customers relative to the forecast at this point, it is appropriate to make an adjustment or calibration to the residential customer forecast reflecting the trending under-forecast. I am recommending a modest increase of an average of 28,126 customers per month in 2026, resulting in an increase of 337,508 bills. In 2027, my recommended increase is an average of 39,425 customers per month, or 473,094 bills.

Q. WHAT ARE YOUR OBSERVATIONS ABOUT OTHER CUSTOMER CLASS FORECASTS?

A. Given my recommendation to calibrate the residential forecast, I also recommend similar "adjust to actual" calibrations for the other classes. I ran a simple trend regression through the forecast errors for July 2024 through February 2025. If the trend variable had a significant p-value (less than 0.10 for my analysis), then I used a trend to account for the adjustment, with an exception for the industrial class which I will discuss later. If the p-value on the trend was greater than 0.10, I took the error in February 2025 (the last month for which actual data was available) and multiplied that by twelve to get the number of bills for the adjustment. Neither the commercial sector nor the street lighting sector had p-values below 0.10, so the recommended adjustment for them was to take the February error amount. This results in my recommendation to reduce the number of commercial customers by just under 1,100 customers, resulting in a downward adjustment of 12,816 bills. The street lighting sector results in a recommended reduction of 612 bills. Figure 1 summarizes the trends for the residential, commercial, and street lighting classes.

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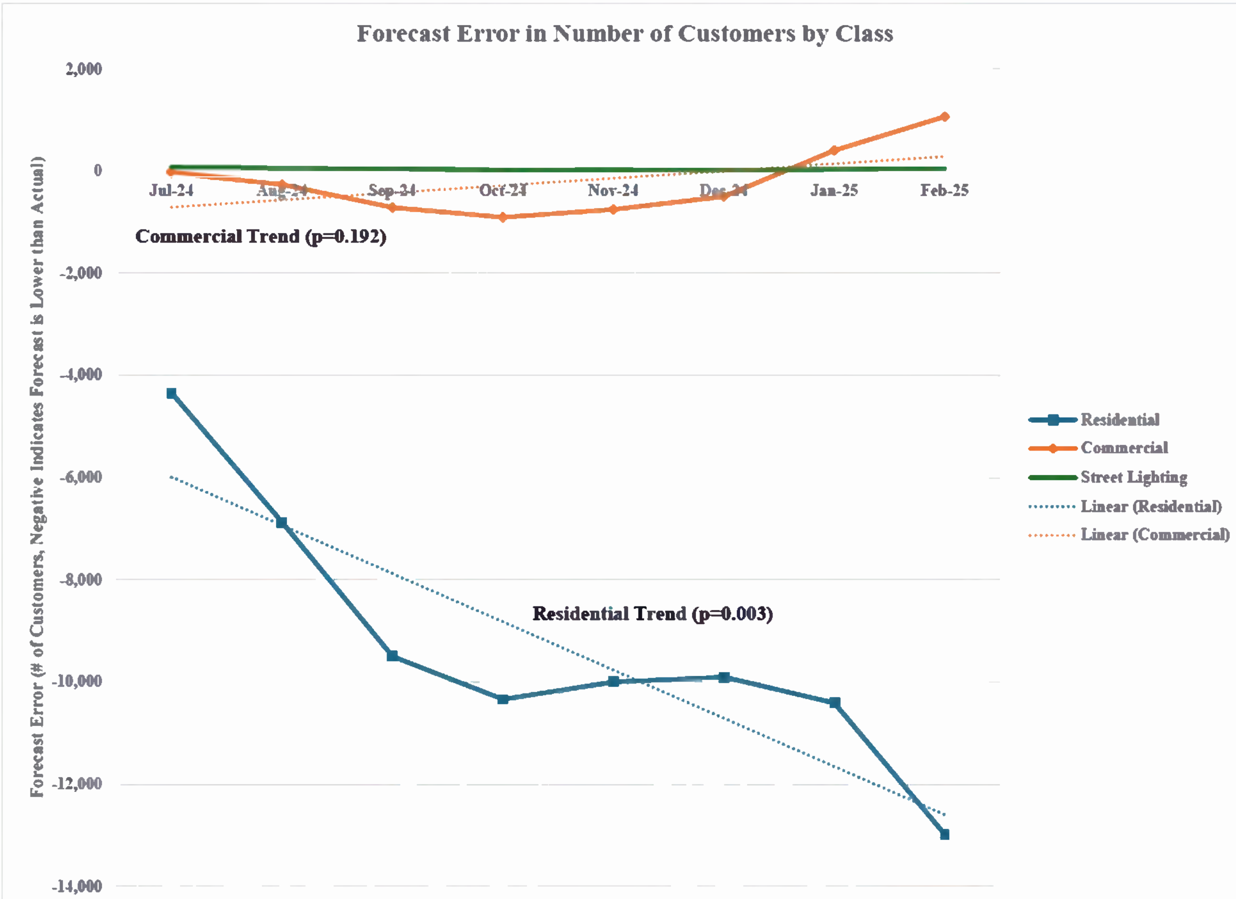
Figure 1: Customer Forecast Error Trends by Class



Q. PLEASE DISCUSS YOUR REVIEW OF THE INDUSTRIAL CUSTOMER FORECAST.

A. There are two issues that I have with the industrial customer forecast. First, as shown in Table 3, a calibration as I have recommended for the other classes would be appropriate. As can be seen, the actual number of customers has dropped significantly between July 2024 and February 2025. According to FPL, the decline is reflective of loss of temporary GS-1 Industrial customers from October 2024 to February 2025.[2]

[2] FPL response to OPC's 11th Set of Interrogatories, No. 307 (See Exhibit JMT-4, page 11).

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Deploying my trend method would result in using a trend for the adjustment to the industrial sector. However, deploying the trend would result in no industrial customers by 2027. Therefore, I recommend using the error in February 2027 as the adjustment and therefore recommend reducing the number of customers by 2,372 and the number of bills by 28,464 to reflect the adjustment for this element of the forecast.

Table 3: Industrial Customers Forecasted versus Actual[3]

Date	Ind Fcst	Actual	Difference	Percent Diff
Jul-24	15,790	15,568	222	1.4%
Aug-24	15,790	15,328	462	3.0%
Sep-24	15,787	14,699	1,088	7.4%
Oct-24	15,782	14,274	1,508	10.6%
Nov-24	15,776	14,032	1,744	12.4%
Dec-24	15,771	14,065	1,706	12.1%
Jan-25	15,768	13,321	2,447	18.4%
Feb-25	15,766	13,394	2,372	17.7%

Q. DO YOU HAVE ANY OTHER CONCERNS ABOUT THE INDUSTRIAL CUSTOMER FORECAST?

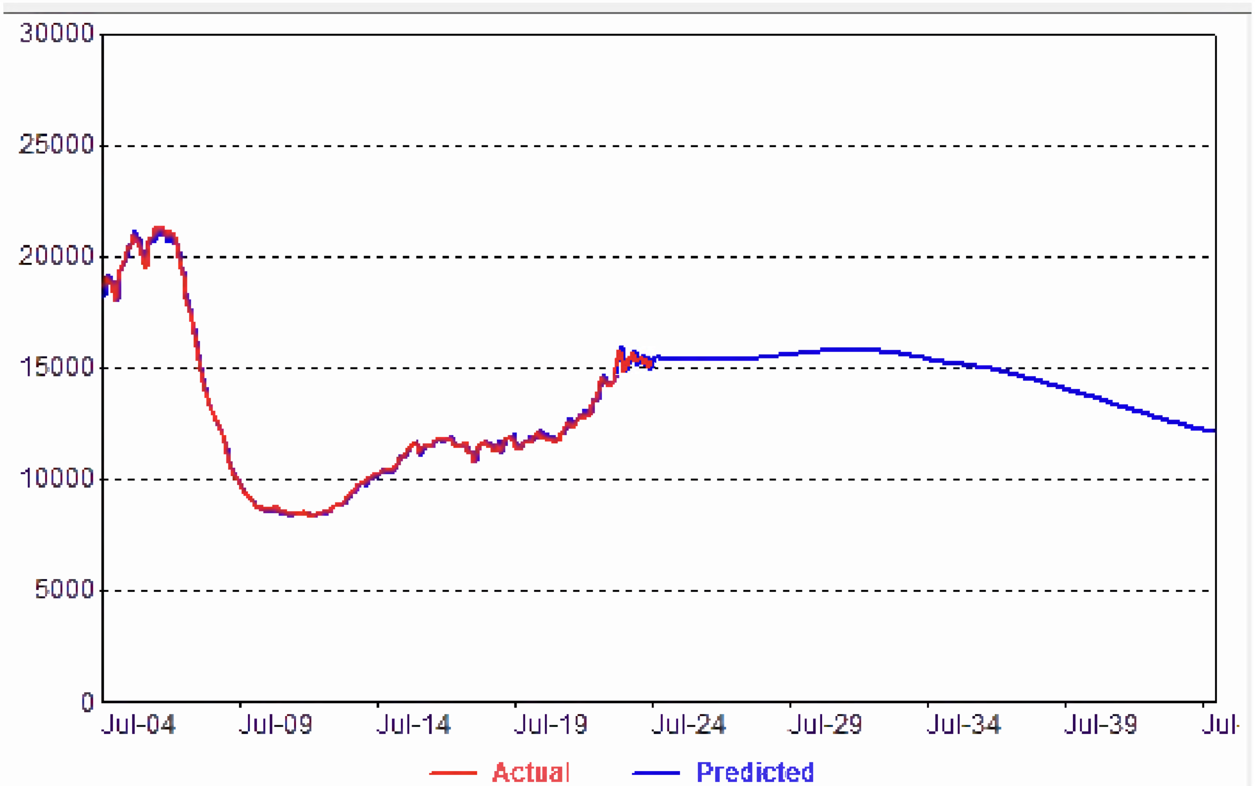
A. Yes. A second concern I have with the industrial forecast is related to what the forecast produces for customers in 2025-2027. FPL predicts the number of customers to be 15,748 in 2025. The forecast then drops to 15,713 accounts in 2026 and 15,729 accounts in 2027, both of which are lower than the 2025 projection. This phenomenon is independent of the loss in GS-1 customers mentioned earlier and is a function of the FPLE Small/Medium Industrial customer forecast model.

[3] FPL response to Staff 1st Set of Interrogatories, No. 6. Represents the sum of customers from Exhibit JMT-4 page 4 and Exhibit JMT-4 page 10.

The primary economic driver in the model is housing starts.[4] The model also includes a lagged dependent variable,[5] a couple of indicator variables for a couple of months in the historical period, and a first order moving average ARIMA[6] component. The model is trained on an extensive historical period, July 2004 through June 2024. The historical period and projected number of customers is shown in Figure 2. Under this model specification, even though housing starts increase in 2016 and 2017, the number of customers declines from 2015 to 2016. This is an antithetical result since the concept of the model is that housing starts should drive customer growth in this sector.

[4] Housing starts are the number of new housing units where construction has begun.
[5] A lagged dependent variable means the forecast for customers in period *x* is based on the number of customers in period *x-1*.
[6] An ARIMA model is an Autoregressive Integrated Moving Average statistical model. The moving average element uses a moving average of prior model error terms.

Figure 2: Small/Medium Industrial Customer History & Forecast, FPL Model[7]



Q. WHAT IS YOUR RECOMMENDATION FOR THE INDUSTRIAL FORECAST?

A. I recommend two remedies to this model. First, I trained the model with data starting in January 2011, thus eliminating the sharp drop-off that is evident in the historical data. Secondly, I excluded the ARIMA moving average element from the forecast. I suspect the interplay between the lagged dependent and the moving average component were partly responsible for the strange result. This model has an adjusted-R^2 of 0.992

[7] This chart is generated by MetrixND software and was obtained from the working papers of Tiffany C. Cohen, the file entitled "Bates # FPL 010628 - 2025 TYSP FPL customers.NDM".

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and a Mean Absolute Percent Error ("MAPE") of 1.01%.[8] It produces a forecast that shows an increase in number of customers from 2025 through 2027 in alliance with increases in housing starts. My recommended model results in an adjustment of 1,008 new bills in 2026 and 1,464 new bills in 2027. These adjustments would be added to the downward adjustments I recommend for the calibration to actual adjustment.

II.B Energy Sales

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS FOR ADJUSTMENTS TO THE ENERGY SALES FORECASTS.

A. The types of adjustments I recommend for energy sales fall into one of three categories:

1. Adjustments associated with the customer adjustment recommendation and calibration to reflect actual energy sales;
2. Demand Side Management ("DSM") adjustments; or
3. Weather normalization adjustments.

Q. DESCRIBE THE ADJUSTMENTS TIED TO YOUR CUSTOMER RECOMMENDATIONS.

A. Given that I have recommended adjusting the number of customers, it is only appropriate to also adjust energy to reflect the additional or fewer customers in each class.

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[8] Adjusted-R^2 is a measure of how well a model fits the underlying data that also takes into account the number of independent variables included in the model. A value close to 1.00 is preferred. MAPE is the average absolute value. percentage error across the in-sample data. An interpretation of a MAPE of 1% is that, on average, the model is off by 1% (either above or below) the actual data values across the historical period over which the model was trained.

For the residential and commercial classes, I applied 2026 and 2027 project UPD to the customer adjustment recommendation to produce the recommended energy sales adjustments associated with the customer adjustments.

The industrial class has two energy adjustments. First, it is interesting to see that although a significant number of GS-1 industrial customers were lost between October 2024 and February 2025, total class energy sales have actually exceeded the load forecast. From July 2024 through February 2025, the forecast has been low on average by 8,509 MWh per month, even with forecast customers much higher than actual. Because the load is not weather sensitive, I recommend an adjustment to reflect this under forecasting, resulting in an increase in forecasted sales of 102,113 MWh. I also made an adjustment for my recommended increase based on revising the FPLE Small Medium Industrial model. For that energy, I applied the average usage per customer to my recommended additional customers.

The street lighting forecast has been too high by 1,652 MWh per month and is not weather sensitive. Annualizing this number results in my recommended downward adjustment of 19,829 MWh in 2026 and 2027. Likewise, the metro class has come in at a higher level than forecasted, so I recommend a small downward adjustment of 3,735 MWh to adjust to actual.

Q. DESCRIBE HOW FPL REFLECTS DSM ADJUSTMENTS IN ITS FORECAST.

A. FPL makes a "post modeling adjustment" to the residential energy sales to reflect DSM program impacts. This means that they reduce energy sales for DSM after using the customer and UPD models to forecast energy sales.

Q. WHAT IS YOUR CONCERN ABOUT THIS DSM ADJUSTMENT?

A. My concern is that FPL might be double-counting energy efficiency effects that would result in under-forecasting energy sales. This could be happening in two ways. First, the historical time series UPD data includes any past DSM program impacts that have already been captured in the meter data. Second, the residential UPD econometric models include a "codes & standards" variable meant to capture the impacts of evolving codes and standards. The coefficient of this variable is negative, meaning that energy usage goes down as codes & standards go up. In the residential models, this codes & standards variable is increasing over time. This is another method for capturing energy efficiency impacts in the residential usage. I have not seen demonstrated evidence by FPL that they are avoiding double-counting of efficiency impacts by including the DSM adjustment and keeping codes & standards in their econometric model. Therefore, I recommend removal of the DSM adjustment for purposes of establishing present revenues in this proceeding.

Q. DID YOU EVALUATE FPL'S APPROACH FOR COMPUTING NORMAL WEATHER FOR ITS LOAD FORECAST?

A. I did. FPL currently uses an average of the most recent 20-years of weather data for estimating normal weather for the forecast period. This approach is one of several used in the industry, although some utilities use longer (30-year) or shorter (10-year) periods. Furthermore, I have seen some utilities that actually use a trend of historical weather to reflect climate change effects. If a trend is present, it might be reasonable to consider a shorter normal period.

Q. DO YOU BELIEVE THE 20-YEAR NORMAL IS APPROPRIATE IN THIS CASE?

A. I do not. I believe use of a ten-year normal period would be appropriate in this case. There is evidence in FPL's own weather data that the last ten years have been warmer than the prior ten years, which might be indicative of a hotter trending local climate. In Table 4, I have shown three different variables used by FPL in its FPLE and NWFL usage models. The CDH80 column represents the sum of July-September Cooling Degree Hours ("CDH") with a base 80 temperature. HDH56 is Heating Degree Hours ("HDH") with a base 56 and is represented as the sum of December through March. Finally, the CDH66 variable is CDH but based on a 66-degree base.

Table 4: CDH and HDH Ranks

	CDH80	Rank	HDH56	Rank	CDH66	Rank
2004	206.7	15	54.0	4	1,162.6	14
2005	246.2	9	50.3	5	1,217.7	8
2006	191.2	20	33.0	9	1,134.6	20
2007	236.1	11	23.8	17	1,191.0	13
2008	199.1	17	62.3	3	1,146.4	19
2009	239.3	10	146.2	1	1,203.4	10
2010	284.3	3	104.1	2	1,269.5	3
2011	248.7	7	30.6	13	1,215.9	9
2012	199.6	16	33.5	8	1,156.0	16
2013	191.4	19	29.6	14	1,150.3	18
2014	211.3	14	31.8	11	1,156.8	15
2015	232.4	12	29.3	15	1,197.7	11
2016	264.0	6	12.5	20	1,239.0	6
2017	277.1	4	44.8	6	1,262.6	4
2018	198.9	18	30.9	12	1,153.3	17
2019	247.5	8	17.8	18	1,223.8	7
2020	272.3	5	33.7	7	1,253.9	5
2021	226.6	13	24.7	16	1,194.9	12
2022	290.6	2	31.8	10	1,272.3	2
2023	321.6	1	12.7	19	1,307.9	1

As can be seen, the first, second, fourth, fifth, and sixth hottest years have all occurred in the most recent ten years (see the two CDH columns and ranks). Similarly, the top 5 coldest years, as measured by HDH56, occurred in the first ten years of the period. This seems to indicate a consistently warmer trend in the most recent ten years.

One consideration when recommending shortening the period used to define normal weather is what that might mean to forecast stability from one period to the next. Using only ten years means every data point has twice the weight in the average as it would in a twenty-year average. This may be an undesirable result, especially if there is generally long-term stability in the weather data. However, in this case, the trend seems convincing enough that it would be preferable to adopt the shorter window in order to achieve normal weather that is more likely to represent actual weather in the next two-to-three years.

Q. HOW DID YOU DETERMINE THE IMPACTS ON THE LOAD FORECAST OF A SHORTER WEATHER NORMALIZATION PERIOD?

A. I calculated new normal weather variables for all residential and commercial models and used FPL's modeling coefficients for those variables to determine the energy impact of shortening the weather normalization period.

Q. CAN YOU PLEASE SUMMARIZE YOUR CUSTOMER AND ENERGY ADJUSTMENT RECOMMENDATIONS?

A. The cumulative effect of the recommendations I am making with respect to the customer and energy forecasts is an increase of roughly 24,700 customers (296,624 bills) and an increase of 1,847 GWh in energy sales in 2026. In 2027, I recommend a cumulative increase of just over 36,000 customers representing 432,666 bills and 2,068 GWh. A summary is provided in Exhibit JMT-2.

II.C Peak Demand

Q. PLEASE SUMMARIZE FPL'S DEMAND FORECAST.

A. FPL uses econometric models to forecast summer and winter peak demands for the FPLE and NWFL regions. The four models include the following independent variables:

- FPLE Summer – the maximum and minimum temperatures on the peak day, non-agricultural employment, a variable representing energy efficiency savings, and an indicator variable[9] for 2020;
- FPLE Winter – minimum temperature on the peak day, a morning temperature on the day prior to the peak, non-agricultural employment; and a variety of indicator variables;
- NWFL Summer – maximum temperature on the day of the peak, non-agricultural employment, and a variable to represent the impact of codes and standards;
- NWFL Winter – minimum temperature on the day of the peak, total population, and a variable to represent the impact of codes and standards.[10]

They then generate an hourly load profile for each region, aggregate them to produce a

[9] An indicator variable (also sometimes called a binary or "dummy" variable) is a variable that has a value of 1 for certain data points and a value of 0 for all other data points. They are often used to control for unusual circumstances known to be in the historical data series that are often single instance events, such as a major storm.
[10] Model variables are included in MFR F-05, Attachment 2.

combined hourly load profile, and then determine the combined summer and winter peak demands which they call a "consolidated peak". The forecasted consolidated peak demands for the summer are 28,664 MW in 2026 and 28,925 MW in 2027. Winter peak demands for 2026 and 2027 are 23,323 MW and 23,648 MW, respectively.

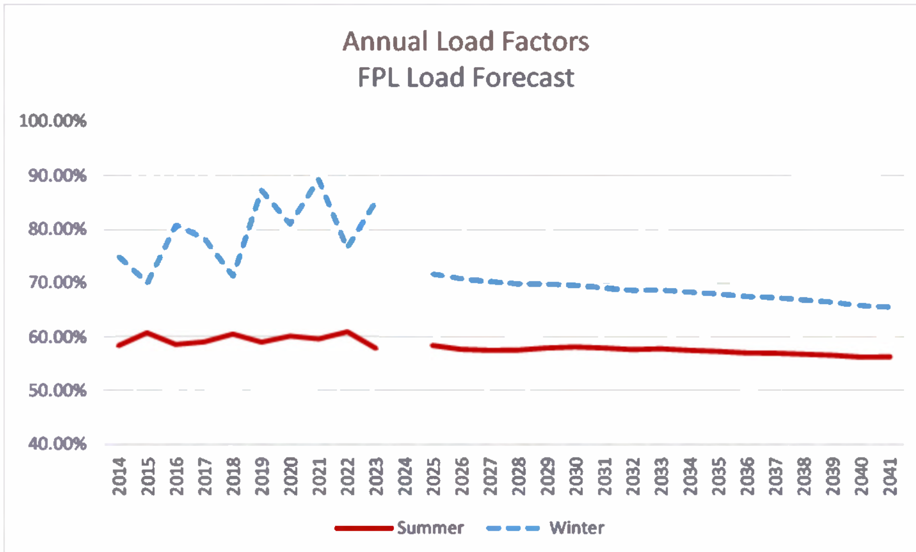
Q. DO YOU HAVE ANY CONCERNS ABOUT FPL'S PEAK DEMAND FORECAST?

A. Yes. I have a few concerns:

- I have a concern with the lack of a consistent modeling theory with respect to peak demands. Three of the four models include a variable for energy efficiency impacts and one does not. Three of the four use employment as an economic driver and one uses population. One of the four models includes an indicator variable for 2020 while the others do not;
- I am also not convinced that for those models that include codes & standards variables that efficiency impacts are not being double-counted since a DSM adjustment is also made; and
- The demand models are completely independent of the energy forecasts. Energy and peak demand are, of course, highly correlated with each other. Considerable effort is put into a bottom-up forecast by FPL, in which trends in residential, commercial, and industrial energy needs are forecasted and aggregated. The relative growth-rates of the different sectors is likely to impact peak demand growth rates. Figure 3 shows historical and projected load factors for the summer and winter seasons based on FPL's load forecast. As can be seen, FPL is projecting load

factor to decline over time, which is inconsistent with the historical period shown in the Figure.

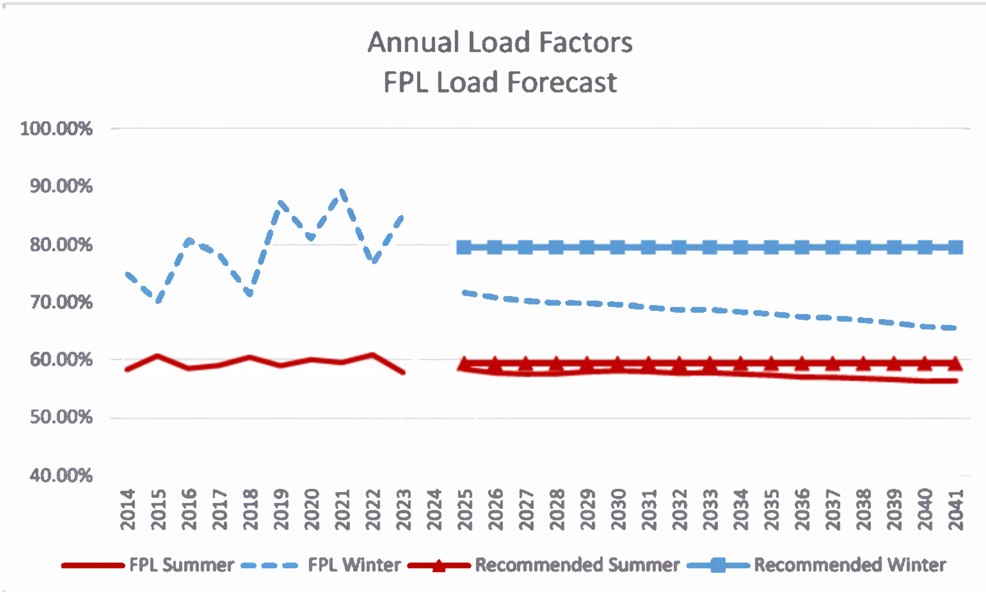
Figure 3: Summer and Winter Load Factors



Q. WHAT DO YOU RECOMMEND TO REMEDY THESE CONCERNS?

A. I recommend using a constant load factor for the forecast period. Peaks can then be computed as the average load factor applied to net energy for load. This assumption means that, for this case, peak demands and energy would grow at the same rate. I recommend using a 10-year average of 2014-2023 load factors, which I derived from data in FPL's 2024 10-Year Site Plan. A ten-year average would be consistent with the ten-year average recommendation for normal weather. My recommendation is to use a summer load factor of 59.4% and a winter load factor of 79.5%. Figure 4 provides a comparison of FPL's forecasted load factors versus my recommendation.

Figure 4: FPL Load Factors vs. JMT Recommended Load Factors



Q. WHAT IS YOUR RESULTANT RECOMMENDED PEAK DEMAND?

A. Applying my recommended load factors to my adjusted net energy for load results in a decrease in peak demands. As shown in Table 5, I am recommending a downward adjustment of nearly 500 MW for summer peaks and a downward adjustment of over 2,000 MW in winter peaks.

Table 5: Recommended Peak Demand Adjustments

		2026				2027			
Line.	Item	FPL	Adj.	JMT	Adjustment	FPL	Adj.	JMT	Adjustment
1	Total Delivered (MWH)	136,773,946	1,847,114	138,621,060		137,600,753	2,068,311	139,669,064	
2	Losses plus Own Use (MWH	7,912,754	106,861	8,019,615		7,960,587	119,658	8,080,245	
3	Net Energy for Load (MWH)	144,686,700	1,953,975	146,640,675		145,561,340	2,187,969	147,749,309	
4	Loss %	5.47%	5.47%	5.47%		5.47%	5.47%	5.47%	
5	Summer Peak (MW)	28,664		28,205	(459)	28,925		28,418	(507)
6	Summer LF	57.6%		59.35%		57.4%		59.35%	
7	Winter Peak (MW)	23,323		21,068	(2,255)	23,648		21,228	(2,421)
8	Winter LF	70.8%		79.45%		70.3%		79.45%	

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III. PRESENT RATE REVENUE ADJUSTMENTS

Q. ARE YOU RECOMMENDING ANY PRESENT RATE REVENUE ADJUSTMENTS?

A. Yes. I am recommending adjustments to present rate revenues that correspond to the adjustments I am recommending in the load forecast. I will discuss the revenue adjustments for each class in turn.

Q. PLEASE EXPLAIN YOUR RECOMMENDED RESIDENTIAL REVENUE ADJUSTMENT.

A. For the residential class adjustment, I used the present RS-1 residential rate. I used FPL's projected split of TY energy in the "First 1,000 kWh" and "Over 1,000 kWh" energy blocks and applied it to my residential energy adjustment amount to determine the amount of energy in each block. This computation results in an upward adjustment of nearly $105 million in 2026 and $120 million in 2027. (See Exhibit JMT-3).

Q. PLEASE EXPLAIN YOUR RECOMMENDED COMMERCIAL REVENUE ADJUSTMENT.

A. For the commercial adjustments, I assumed the adjustments would flow through the GS-1 General Service and GSD-1 General Service Demand rate schedules. I assumed the number of customers and energy would be split in similar proportions to FPL's projected TY billing units in those two rates. I added demand in the GSD-1 rate by applying the FPL TY GSD-1 load factor to the GSD-1 energy adjustment amount. This results in a decrease in base charges and an increase in non-fuel energy and demand

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charges. The net impact is an increase of present rate revenues of just under $23 million in 2026 and nearly $24 million in 2027.

Q. PLEASE EXPLAIN YOUR RECOMMENDED INDUSTRIAL REVENUE ADJUSTMENT.

A. For the industrial adjustments, I assumed the adjustments would flow through the GS-1 General Service, the GSD-1 General Service Demand, and the GSLD-1 General Service Large Demand rate schedules. I assumed the number of customers and energy would be split in similar proportions to FPL's projected TY billing units in those three rates. I added demand in the GSD-1 and GSLD-1 rates by applying the FPL TY load factors to the energy adjustment amounts in each rate. This results in a decrease in base charges and an increase in non-fuel energy and demand charges. The net impact is an increase of present rate revenues of $6.3 million in 2026 and $6.4 million in 2027.

Q. PLEASE EXPLAIN YOUR RECOMMENDED STREET LIGHTING REVENUE ADJUSTMENT.

A. The street lighting classification revenue calculation is complicated by the fact that the number of customers is not directly tied to the number of devices and that there are street lighting rates that do and do not meter and charge for energy. Given that I am recommending an energy decrease to this class, I felt it would be unfair to FPL to assume all of the adjustments would come from unmetered lighting. Therefore, I have assumed the adjustment is reflective of adjustments to SL-1 and SL-1 Metered rates. For energy, I used FPL's TY energy split between the two schedules (75.5% of energy is in SL-1 based on FPL's estimated energy per device and number of devices). Then, for SL-1 Metered base charges, I used FPL's TY energy per bill and applied that factor to the SL-1 Metered energy. For SL-1, I applied FPL's TY average energy per device to compute the number of devices. I then applied FPL's TY average revenue per device times the derived number of devices to get the revenue impact. In total, I recommend a downward adjustment of $170 thousand dollars for street lighting in 2026 and 2027.

Q. PLEASE EXPLAIN YOUR RECOMMENDED METRO REVENUE ADJUSTMENT.

A. Simple application of the Metro rate to recommended Metro adjusted energy sales results in my recommendation to reduce Metro revenue by $86 thousand per year.

Q. CAN YOU SUMMARIZE YOUR REVENUE ADJUSTMENT RECOMMENDATIONS?

A. My recommended present rate revenue adjustments are summarized in Exhibit JMT-3 and in Table 5. In total, I am recommending an increase to present base rate revenues of $133,031,551 in 2026 and $150,474,873 in 2027.

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Table 5: Summary of Recommended Present Rate Revenue Adjustments

2026	Residential	Commercial	Industrial	Street Lights	METRO	Total
Base Charges	$3,243,452	($198,268)	($428,537)	($2,792,761)	$0	($176,114)
Non-Fuel Energy Charges	$104,381,866	$14,007,521	$3,739,588	($169,880)	($85,573)	$121,873,523
Demand Charges	$0	$8,767,950	$2,566,192	$0	$0	$11,334,143
Total Revenue Adjustment	$107,625,318	$22,577,204	$5,877,243	($2,962,641)	($85,573)	**$133,031,551**

2027	Residential	Commercial	Industrial	Street Lights	METRO	Total
Base Charges	$4,546,433	($198,268)	($421,476)	($2,934,783)	$0	$991,907
Non-Fuel Energy Charges	$119,462,053	$14,709,251	$3,771,694	($169,880)	($85,573)	$137,687,546
Demand Charges	$0	$9,207,195	$2,588,225	$0	$0	$11,795,420
Total Revenue Adjustment	$124,008,487	$23,718,179	$5,938,443	($3,104,663)	($85,573)	**$150,474,873**

IV. SUMMARY OF RECOMMENDATIONS & CONCLUSIONS

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO LOAD FORECASTING?

A. I recommend several adjustments be made to FPL's load forecast. I recommend adjustments to the number of customers by sector, with updates made to reflect the most recently known actual customer counts. For energy sales, I recommend adjustments to reflect adjusted number of customers, a change to a ten-year normal for defining normal weather variables, adjustments to reflect current modeling impacts, and removal of the DSM post-modeling adjustment made by FPL. As shown in Exhibit JMT-2, my recommendation is to add nearly 25,000 customers and 1.8 million MWh to FPL's 2026 forecast. Finally, I recommend using a ten-year average load factor applied to net energy for load to produce adjusted peak demand forecasts. The recommendation results in a downward adjustment of approximately 500 MW in summer peak demands and over 2,000 MW in winter peak demands, as shown in Exhibit JMT-2.

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Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS FOR ADJUSTMENTS TO BASE RATE REVENUES.

A. I applied various present base rates to the residential, commercial, industrial, street lighting, and metro forecast adjustments that I am recommending. This produces a recommended adjustment to present base rate revenues. As shown in Exhibit JMT-3, this results in a recommended additional $133,031,551 in base rate revenue under present rates in 2026 and an additional $150,474,873 in 2027.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

C24-3855

BY MR. PONCE:

Q Mr. Thomas, did your prefiled testimony in this docket also contain four exhibits labeled JMT-1 through JMT-4?

A Yes.

Q For the record, I believe those exhibits have been identified on the CEL as Exhibits 184 through 187.

Do you have any corrections to for your exhibits?

A No.

Q And have you prepared a summary of your testimony?

A Yes, I have.

Q Please provide it.

A Sure.

Good afternoon, Commissioners. Thank you for having me.

In my direct prefiled testimony, I make recommendations regarding FPL's load forecast and present rate revenue projections. For the load forecast, I make recommendations concerning the forecast of number of customers, the forecast of class energy sales and the forecast for system peak demand.

For residential customers, I observed that the forecast is currently forecasting lower than actual for the most recent eight months available. I observed that that forecast error is generally increasing over the eight months, and that the trend is likely to continue. I, therefore, recommend a calibration adjustment to test year number of residential customers to account for this error. I then recommend making such calibration adjustments to other rate class customer forecasts. I developed a trend test to determine whether the trend -- whether to trend the error adjustment or whether to annualize the error in the most recent month.

In addition to this calibration analysis, I recommend adjusting the econometric model specifications for FPLE small/medium industrial class. I observe that the number of customers in this class goes down from 2025 through 2027 even though the economic variable goes up. I recommend an updated model specification for this class that still uses the same economic variable, housing starts, but adjust the historical period used and removes a moving average component of the model.

For energy sales forecast, I made three recommendations. First, I make adjustments to the energy sales consistent with the adjustments to the customer forecast that I recommend. My second adjustment recommendation is to remove post modeling demand-side management impacts, since some of the energy models also include codes and standards terms. My concern is that there could be double counting of energy efficiency savings by having both elements in the forecast.

For my final adjustment to the energy forecast, I recommend shortening the weather normalization period from 20 years to 10 years. This primarily based on the observation that the weather variables used by FPL in developing its load forecast demonstrate a warming trend.

My testimony then moved on to FPL's peak demand forecast. I raised three primary concerns about the peak forecast. The first is an inconsistency in the general framework used for forecast peak demands, as the variables used for each season and each territory are different.

Second, I have the same concern about codes and standards and DSM impacts as I had with the energy models.

Finally, I note that the lack of any tie-in to energy produces load factor projections that I find to be unrealistic with declining forecasted trends and load factor. I demonstrate that winter load factors have been generally increasing since 2014, while summer load factors have been fairly stable. I conclude the declining load factors are, therefore, inconsistent with historical trends. To remedy this concern, I recommend using a ten-year average historical load forecast applied to projected energy requirements to produce peak demand forecast. That load factor then would be held constant into the future.

Concluding my recommendations on the load forecast, my testimony then discusses adjustment to present rate revenues. These adjustments are only to reflect the impacts associated with my load forecast adjustments. My testimony details how I use test year billing units to split energy adjustments when needed to model revenue impacts.

My conclusion is a recommended -- excuse me -- a recommended increase of approximately $133 million in present base rate revenues in 2026 associated with the load forecast adjustments. In 2027, that adjustment is an additional $150 million in present base rate revenues.

That concludes my summary of my testimony.

Q Thank you.

MR. PONCE: OPC would tender the witness for cross-examination.

CHAIRMAN LA ROSA: Thank you.

FEL?

MS. McMANAMON: No questions.

CHAIRMAN LA ROSA: FEIA?

MR. MAY: No questions.

CHAIRMAN LA ROSA: Walmart?

MS. EATON: No questions.

CHAIRMAN LA ROSA: FRF?

MR. BREW: It no questions?

CHAIRMAN LA ROSA: FIPUG?

MR. MOYLE: No questions.

CHAIRMAN LA ROSA: FPL?

MR. BURNETT: No questions.

CHAIRMAN LA ROSA: Staff?

MR. STILLER: No questions.

CHAIRMAN LA ROSA: Commissioners, do we have any questions?

Seeing none, back to you, OPC, for redirect.

MR. PONCE: No redirect from me.

At this time, OPC asks that Mr. Thomas' previously identified Exhibits No. 184 through 187 please be entered into the record.

CHAIRMAN LA ROSA: All right. Seeing no objection, so moved.

(Whereupon, Exhibit Nos. 184-187 were received into evidence.)

CHAIRMAN LA ROSA: Is there anything else to be moved into the record? No? Excellent.

Mr. Thomas, thank you very much for your testimony today.

THE WITNESS: Thank you.

CHAIRMAN LA ROSA: You are excused.

(Witness excused.)

(Transcript continues in sequence in Volume 15.)

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 28th day of October, 2025.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028