BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

DOCKET NO. 20240026-EI

Petition for rate increase by Tampa Electric Company.
____/

DOCKET NO. 20230139-EI

Petition for approval of 2023 depreciation and dismantlement study, by Tampa Electric Company.
____/

DOCKET NO. 20230090-EI

In re: Petition to implement 2024 generation base rate adjustment provisions in paragraph 4 of the 2021 stipulation and settlement agreement, by Tampa Electric Company.
____/

VOLUME 15 - PAGES 3303 - 3558

PROCEEDINGS: HEARING

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

DATE: Thursday, August 29, 2024

TIME: Commenced: 8:00 a.m.
Concluded: 7:00 p.m.

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

TRANSCRIBED BY: DEBRA R. KRICK
Court Reporter and
Notary Public in and for
the State of Florida at Large

APPEARANCES: (As heretofore noted.)

I N D E X

P R O C E E D I N G S

(Transcript follows in sequence from Volume 14.)

CHAIRMAN LA ROSA: All right. Let's reconvene here. I believe we have got two witnesses left with TECO, if my math is accurate --

MR. WAHLEN: Yes.

CHAIRMAN LA ROSA: -- so let me kick it back over to you guys to introduce your next witness.

MR. WAHLEN: Thank you, Mr. Chair. Tampa Electric calls Jeff Chronister.

CHAIRMAN LA ROSA: Mr. Chronister, welcome. Do you mind standing and raising your right hand so we can administer the oath?

THE WITNESS: Yes, sir.

Whereupon,

JEFF CHRONISTER

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: Thank you.

EXAMINATION

BY MR. WAHLEN:

Q And when you get settled, would you please

state your name?

A   Jeff Chronister.

Q   And who is your current employer, and what's your business address?

A   My current employer is Tampa Electric. My business address is 702 North Franklin Street, Tampa, Florida.

Q   And did you prepare and cause to be filed on this docket, on April 2nd, 2024, prepared direct testimony consisting of 47 pages?

A   I did.

Q   And did you adopt the testimony of Richard Latta, now titled the direct testimony of Jeff Chronister, Volume II, consisting of 66 pages of prepared direct testimony on May 2nd, 2024.

A   I did.

Q   And did you prepare and cause to be filed in this docket, on July 2nd, 2024, prepared rebuttal testimony consisting of 63 pages?

A   I did.

Q   And did you prepare and cause to be filed replacement pages 41 and 42 of your direct testimony Volume II on May 23rd, 2024?

A   I did.

Q   And the company has file two updates to its

revenue requirement calculation in this case, is that correct?

A That's correct.

Q And the first one was on July 24th, 2024?

A Yes.

Q And that's been identified as Exhibit No. 217 on the CEL?

A Yes.

Q And did the company also file another update on August 22nd, 2024?

A Yes, we did.

Q And that's been identified as 835 on the CEL?

A Yes.

Q And did that update the company's revenue requirement to reflect the increase in the PTC rate, a 20-year depreciation for energy storage, and reductions to the '26 and '27 SYA by removing some programs?

A Yes, it did.

Q Now, have you updated all of your testimony exhibits to reflect the changes in the 20 -- April 22nd -- or August 22nd update?

A We have made all the updated calculations.

Q Okay. And those are all in the exhibit, not -- you didn't go back through your testimony and update all your testimony, right?

A Exactly. That's correct.
Q But we can rely on the exhibit?
A Yes.
Q Okay. Do you have any other additions or changes to your testimony?
A No, I don't.
Q Okay. With those revisions and updates and replacements, if I were to ask you the questions contained in you prepared direct testimony, both the original and Chronister II and your rebuttal testimony, would your answers be the same?
A Yes, they would.

MR. WAHLEN: Mr. Chairman, Tampa Electric requests that the prepared direct, adopted and rebuttal testimony of Mr. Chronister be inserted into the record as though read.

CHAIRMAN LA ROSA: Okay.

(Whereupon, prefiled direct testimony of Jeff Chronister was inserted.)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFF CHRONISTER

Q. Please state your name, address, occupation, and employer.

A. My name is Jeff Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Vice President Finance.

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

A. I am responsible for maintaining the financial books and records of the company and for the determination and implementation of accounting policies and practices for Tampa Electric. I am also responsible for budgeting activities within the company, which includes business planning and financial planning & analysis, as well as general accounting, regulatory accounting, plant accounting, tax accounting, financial reporting, accounts payable and payroll.

Q. Please summarize your educational background and business experience.

A. I graduated from Stetson University in 1982 with a Bachelor of Business Administration degree in Accounting. I became a Certified Public Accountant in the State of Florida in 1983. Upon graduation I joined Coopers & Lybrand, an independent public accounting firm, where I worked for four years before joining the company in 1986. I started in Tampa Electric's Accounting department, moved to TECO Energy's Internal Audit department in 1987, and returned to the Accounting department in 1991. I have led Tampa Electric's Accounting department since 2003, and I led the Peoples Gas Accounting department from 2009 to 2018. I became Vice President Finance for Tampa Electric in 2018.

For the last six years, I have been responsible for treasury and finance functions, including short-term and long-term debt, cash management and debt compliance. In addition, my team works with Emera financial personnel on debt issuances, and preparation of financial information and communications for credit rating agencies and investment analysts.

Q. Have you previously testified before the Florida Public

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Service Commission ("FPSC" or the "Commission")?

A. Yes. I have testified or filed testimony before this Commission in several dockets.

I testified for Tampa Electric in Docket No. 20210034-EI, which was Tampa Electric's last base rate proceeding.

I filed testimony in the following dockets:

(1) Docket No. 20130040-EI, Tampa Electric Company's Petition for An Increase in Base Rates and Miscellaneous Service Charges;

(2) Docket No. 20080317-EI, Tampa Electric Company's Petition for An Increase in Base Rates and Miscellaneous Service Charges;

(3) Docket No. 19960007-EI, Tampa Electric's Environmental Cost Recovery Clause;

(4) Docket No. 19960688-EI, Tampa Electric's environmental compliance activities for purposes of cost recovery;

(5) Docket No. 20170271-EI, Petition for recovery of costs associated with named tropical systems during the 2015, 2016, and 2017 hurricane seasons and replenishment of storm reserve subject to final true-up; and

(6) Docket No. 20200144-EI, Petition for Limited Proceeding to True-Up First and Second SoBRA by Tampa Electric Company.

I also served on a panel of witnesses during the final hearing in Docket No. 20200065-EI, which addressed the company's amortization reserve for intangible software assets.

Q. What are the purposes of your direct testimony?

A. The purposes of my direct testimony are to explain how the company's financial profile has changed from its last rate case; discuss the importance of Tampa Electric's financial integrity and credit ratings; present the company's proposed capital structure and weighted average cost of capital for the 2025 test year; and describe the company's projected financial condition for 2026 and 2027 and regulatory options for those years including the company's request for subsequent year adjustments ("SYA"). I explain why the Commission should approve the company's proposed 54 percent equity ratio (investor sources) as part of my capital structure discussion.

Q. Have you prepared an exhibit to support your direct

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testimony?

A. Yes, Exhibit JC-1, entitled the Exhibit of Jeff Chronister, was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of two documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Jeff Chronister
Document No. 2	Final Oder No. PSC-2021-0423-S-EI Approving 2021 Stipulation and Settlement Agreement (without Attachment C – Tariffs)

Q. Do you sponsor any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I sponsor or co-sponsor the MFR Schedules listed in Document No. 1 of my exhibit. The contents of these MFR Schedules were derived from the business records of the company and are true and correct to the best of my information and belief.

Q. How does your prepared direct testimony relate to the prepared direct testimony of other company witnesses?

A. My testimony explains and supports the company's proposed 2025 capital structure and weighted average cost of capital (overall rate of return). Tampa Electric witness Dylan D'Ascendis's testimony supports the company's proposed mid-point return on equity ("ROE") of 11.50 percent, which is one of the inputs to the calculation of the company's overall rate of return. Tampa Electric witness Valerie Strickland's testimony explains the income tax related components in our proposed capital structure.

Tampa Electric witness Richard Latta's direct testimony explains the company's proposed 2025 test year; its budgeting process and 2025 budget; its proposed 2025 rate base, net operating income, and 2025 proposed revenue requirement increase; and the revenue requirements for the company's 2026 and 2027 SYA. He uses the proposed 2025 capital structure and overall weighted average cost of capital discussed in my testimony in his calculation of the company's proposed 2025 revenue requirement increase.

My testimony also discusses the company's need for capital to pay for the projects and activities necessary to continue improving the efficiency, sufficiency, and adequacy of the company's facilities and services, and to continue improving the safety, security, reliability, and resilience of the company's operations. These projects and activities are explained by our President and Chief Executive Officer Archie Collins and our operating witnesses. Mr. Latta explains how they become part of the financial budgets we use to plan and manage our operations. My testimony explains why maintaining Tampa Electric's financial integrity is important to the company, its customers, and its ability to raise capital on reasonable terms and conditions.

(1) FINANCIAL PROFILE CHANGES FROM THE COMPANY'S LAST RATE CASE

Q. How has Tampa Electric's financial profile changed since its last rate case in 2021?

A. Our last rate case was filed in April 2021 and concluded when the Commission approved the 2021 Stipulation and Settlement Agreement between Tampa Electric and the parties ("2021 Agreement"). Document No. 2 of my exhibit is excerpts from the Order approving the 2021 Agreement.

From the actual 13-month average in 2022 (the test year in the previous case) to the projected 13-month average in

2025 (the test year in this filing), rate base has grown $2.2 billion, or by about nine percent a year by investing capital in assets to serve our growing customer base and improve our systems. This level of rate base growth reflects a deliberate and thoughtful approach to improving the efficiency, sufficiency, and adequacy of the company's facilities and services, and the company's reasonable and prudent efforts to continue improving the safety, security, reliability, and resilience of the company's operations.

The company's rate base growth has affected other parts of its financial profile. All other things being equal, increasing rate base increases depreciation expense, operations and maintenance ("O&M") expenses, and taxes other than income taxes (primarily ad valorem taxes), because there are more assets to depreciate and to operate and maintain, and that are subject to property taxes. Despite our rate base growth and the impacts of inflation, we have been able to keep our other O&M expense growth since 2021 under the Commission's benchmark. Financial market changes, including higher interest rates, have increased our overall cost of capital since 2021.

Q. How do these changes influence the company's proposed 2025 rate increase request?

A. Our rate base growth since 2022 has a 2025 revenue requirement impact of approximately $185 million. Higher depreciation expense, caused by rate base growth and higher proposed depreciation rates, has a revenue requirement impact in 2025 of about $160 million. The effect of higher O&M expenses, taxes other than income taxes, and cost of capital have a 2025 revenue requirement impact of approximately $45 million, $20 million, and $145 million, respectively. These impacts total approximately $555 million.

Q. If the collective impact of the items above is approximately $555 million, why is the company's request for revenue increase for 2025 only $296.6 million?

A. Three things have tempered the company's 2025 revenue increase request: (a) incremental revenue provided in the 2021 Agreement, (b) general revenue from load growth, and (c) lower income tax expense attributable to the company's decision to claim the production tax credit ("PTC") for solar assets placed in service after January 1, 2022.

Q. Please explain further.

A. The 2021 Agreement provided incremental revenue in 2023 and 2024 through generation base rate adjustments ("GBRA") and a ROE Trigger. The GBRA provided cost recovery for the company's Big Bend Modernization project and certain new solar generating facilities ("Solar Wave 2"). The annual dollar increases for the two GBRA and the ROE trigger were approximately $90 million, $20 million and $10 million, respectively, for a total of $120 million.

Load growth, since 2022, is expected to generate incremental base revenues of approximately $65 million in 2025.

Income tax expense in 2025 is projected to be over $70 million lower than the actual expense in 2022, primarily due to the company's decision to elect the PTC and other items discussed in the testimony of Ms. Strickland.

These factors total approximately $255 million. The difference between the $555 million above and the counterbalancing factors of $255 million equal approximately $300 million.

Q. Are the changes in the expense elements referred to above reasonable?

A. Yes. Depreciation, O&M, taxes other than income and interest expense have increased as a result of asset growth to serve customers as well as economic conditions during the settlement period. I will discuss each expense element in more detail below.

Q. How has depreciation expense changed, and is the change reasonable?

A. The company's 2025 Jurisdictional Adjusted Depreciation & Amortization Expense is forecasted to be $158.5 million higher than the actual amount for 2022. This change is reasonable given (a) the company's Jurisdictional Adjusted Plant in Service growth of roughly $1 billion per year, and (b) the $56.3 million impact of the company's Depreciation and Dismantlement Study, which was filed on December 27, 2023, in Docket No. 20230139-EI. The increases in new depreciation rates results in a 2025 expense increase of $46.9 million and the increase in the new dismantlement accrual results in a 2025 expense increase of $9.4 million. These changes are discussed further by Tampa Electric witnesses Ned Allis and Jeff Kopp in their direct testimony.

Q. Is the forecasted amount for 2025 O&M expense reasonable?

A. Yes. The company's 2025 Adjusted O&M expense (the sum of O&M Other, Fuel and Purchased Power) is $71.9 million lower than the Commission Benchmark amount. The Commission's O&M Benchmark test measures a company's projected test year O&M expense levels against the O&M expense levels in a benchmark year (2020 in this case) escalated annually by a multiplier reflecting inflation and customer growth. The company's results against the O&M Benchmark are shown on MFR Schedule C-37. Being more than $70 million below the benchmark is important evidence that the company's efforts to control O&M expenses have worked, and that our projected 2025 O&M expense levels are reasonable.

Q. What is the performance against the O&M benchmark for 2025 in each of the company's functional expense groups?

A. Tampa Electric is well below the benchmark in all functional areas, except for the Production area. The benchmark difference in Production is caused by planned outage timing and solar operations expansion. Tampa Electric witness Carlos Aldazabal explains their influences further in his testimony.

The functional expense groups where our projected 2025 level of O&M expenses are under the benchmark, and the amounts by which they are under are:

Transmission	$4.6 million under
Distribution	$13.4 million under
Customer Accounts	$6.5 million under
Customer Service and Information	$2.4 million under
Sales Expenses	$0.02 million under
Administrative and General	$56.0 million under

Q. Did inflation impact the company during the 2022 to 2024 settlement period?

A. Yes. General inflation increased the prices Tampa Electric pays for the goods and services it uses to provide service to customers. As noted by Mr. Collins in his testimony, the cost of transformers, substation equipment, switchgears, and poles, increased from 2021 to 2023 by 49 percent, 36 percent, 21 percent, and 34 percent respectively. The price of Grain Oriented Electrical Steel ("GOES") doubled since January 2020, and the price of copper increased by 50 percent over the same period. Distribution line contractor rates have increased over 45 percent since 2021. Tampa Electric witness Lori Cifuentes discusses the general level of inflation in her direct testimony.

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Q. Has the company experienced other cost increases during the settlement period?

A. Yes. Company labor costs, bad debt expense, and the cost of property and casualty insurance have all gone up due to general economic conditions and market forces beyond the control of the company. Tampa Electric witnesses Marian Cacciatore, Karen Sparkman, and Mr. Latta discuss these increases in their direct testimony.

Q. What did Tampa Electric do to counteract these price increases?

A. Our proposed overall 2025 O&M expense level is well below the Commission's benchmark because the company focused on cost control and made business decisions to counteract upward cost pressures. The list of items that result in positive impact include:

(1) The company has a culture that focuses on process improvements, operational optimization, technology enhancements and innovations for efficiency. As a result, the company's O&M expense average annual growth rate from 2013 to 2023 was roughly one half of one percent.

(2) The company monitors market conditions and opportunities to lower expenses through prudent decision-making. An example of this is the change in the cost for providing medical coverage for retirees. With interest rates elevated, a higher discount rate was used to calculate the actuarial obligation, which lowered the 2025 expense. In addition, we replaced one of our retiree pharmacy providers with a fully insured pharmacy option. The combination of these two changes resulted in almost $3 million of expense reduction in 2025.

(3) The company recognizes that with the growth in capital investments comes the opportunity to appropriately charge a greater amount of Administrative & General ("A&G") Expense to capital. From 2020 to 2023, the company increased the amount of A&G capitalized by $10 million. The forecasted 2025 expense reflects this $10 million expense reduction from the 2020 amount.

(4) 2025 O&M expense is lower by $5.5 million due to the ten-year amortization of the $55 million revenue requirement benefit from PTC deferred during the term of the 2021 Agreement. Consistent with the 2021 Agreement, the company established a regulatory liability over the period 2022 to 2024 so that customers would receive all of

the benefits of the Production Tax Credits related to our investments in solar generation placed in service since 2022. Ms. Strickland discusses PTC impacts in further detail in her testimony.

Q. What caused the increase in the expense for taxes other than income ("TOTI") since 2022?

A. Our TOTI increased from $83.9 million to $101.6 million from 2022 to 2025, which is an increase of approximately seven percent per year. The predominant component of TOTI is ad valorem property tax expense, which reflects the local property taxes levied on the assets we use to serve our customers. Property taxes have grown at the same reasonable pace as the growth of our assets to serve customers. The overall amount of TOTI in the test year is reasonable.

Q. Please describe the recent changes to Peoples' legal structure and how it impacted Tampa Electric Company.

A. Effective January 1, 2023, the assets, liabilities, and equity of the Peoples Gas System, a division of Tampa Electric Company were transferred into a separate corporation named Peoples Gas System, Inc., which is a wholly owned subsidiary of newly formed gas operations holding company, TECO Gas Operations, Inc., which is a subsidiary of TECO Energy, Inc. I will refer to this transaction as the "2023 Transaction" in the remainder of my direct testimony.

Q. How did the 2023 Transaction impact Tampa Electric?

A. During 2023, Tampa Electric provided short-term debt funding to Peoples through the Intercompany Debt Agreement at Tampa Electric's prevailing cost of short- and long-term debt borrowings. The Intercompany Debt Agreement remained outstanding until December 20, 2023 when Peoples obtained their own stand-alone financing and repaid Tampa Electric all principal and interest due on the Intercompany Debt Agreement in the amount of $956 million in addition to $38 million in interest accrued subsequent to January 1, 2023. Peoples has now (1) established its own independent credit rating(s), (2) made short- and long-term borrowing arrangements with its lenders, and (3) paid off its obligations under the Intercompany Debt Agreement with Tampa Electric.

Q. How will the 2023 Transaction impact Tampa Electric borrowing costs in 2024 and 2025?

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A. The 2023 Transaction and Peoples repayment of their Tampa Electric debt will result in a projected decrease in Tampa Electric's borrowing cost starting in 2024. Tampa Electric was able to use the proceeds from the People's repayment to repay short term debt outstanding that would have otherwise been refinanced with long-term debt issued at market interest rates that were at the time approximately 100 basis points higher than the interest rates of the long-term debt previously allocated to Peoples and absorbed by Tampa Electric upon the repayment of the intercompany debt agreement by Peoples.

Q. Has Tampa Electric realized any other recent savings impacting the company's cost of debt.

A. The company's weighted-average interest rate on borrowings outstanding under the credit facilities and commercial paper at December 31, 2023 and 2022 was 5.7 percent and 5.0 percent, respectively. On January 30, 2024, Tampa Electric completed a five-year term, $500 million bond issuance at a 4.90 percent interest rate ("2029 Notes"). Given the rise in interest rates experienced in 2023 and 2022, Tampa Electric benefited from not accessing the debt markets in 2023 and then in January of 2024, issuing long-term debt below the weighted average cost of debt

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experienced by the company in 2023. The company's strategic approach to debt financing is a testament to Tampa Electric's favorable credit standing and targeted approach to access the capital markets at times that help the company achieve its goal of securing a lower cost of debt.

Q. Does Tampa Electric expect to be involved in any other corporate restructuring in 2024?

A. Yes. TECO Energy plans to move Tampa Electric and Peoples Gas System, Inc. into a new holding company to be wholly owned by Emera US Holdings, Inc. ("EUSHI"). This nontaxable transaction will likely be executed before the final rates in this case are approved and will serve to segregate the utility operations in Florida from those in other states. It will have no impact on the affiliate costs allocated to or from Tampa Electric.

Q. Did the company's financial profile as shown in the MFR Schedules change in any other major way?

A. Yes. The 2021 Agreement established a Clean Energy Transition Mechanism ("CETM"), which changed the way certain assets are reflected in our financial statements. CETM assets and expenses do not affect the revenue request in this filing.

The CETM assets and transactions are presented in the 2023, 2024 and 2025 MFR Schedules according to the accounting treatment implemented in our company’s books and records when the 2021 Agreement went into effect. This treatment involved re-classifying the related assets and reserve balances from Property, Plant and Equipment accounts into Regulatory Asset (182) accounts. The CETM income statement transactions are recorded in the appropriate FERC accounts related to regulatory assets.

On the rate base MFR Schedules, the CETM rate base amount is reflected in the System Per Books Working Capital. Since CETM recovery is outside of base rates, the CETM rate base amount is adjusted out so that it is not reflected in Jurisdictional Adjusted Rate Base. Likewise, on the net operating income MFR Schedules, the CETM transactions are reflected in the System Per Books amounts, and then adjusted out so that they are not reflected in the Jurisdictional Adjusted NOI amounts. Tampa Electric witness Ashley Sizemore explains the company’s proposed update to the CETM in her direct testimony.

Q. Given the financial changes discussed above, what net operating income is forecasted for the company's test year and what return does that represent?

A. Tampa Electric's 2025 Jurisdictional Adjusted net operating income is forecasted to be $501.4 million. As shown on MFR Schedule A-1, without the rates we seek in this petition, that net operating income would result in a rate of return of 5.12 percent. This would equate to a ROE of 6.70 percent in 2025. As shown on MFR Schedule D-9, the effect on the company's financial integrity indicators would be substantially negative and could negatively impact the credit ratings of Tampa Electric. In the next section of my testimony, I will discuss the importance of financial integrity and credit ratings.

(2) FINANCIAL INTEGRITY AND CREDIT RATINGS

Q. What is financial integrity?

A. Financial integrity refers to a relatively stable condition of liquidity and profitability in which the company can meet its financial obligations to investors while maintaining the ability to attract investor capital as needed on reasonable terms, conditions, and costs.

Q. How is financial integrity measured?

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A. Financial integrity is a function of financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations. The level of cash flows and the percentage of debt, or financial leverage, in the capital structure is a key determinant of financial integrity. As the percentage of debt in the capital structure increases so do the fixed obligations for the repayment of that debt. Consequently, as financial leverage increases the level of financial distress (financial risk) increases as well. Therefore, the percentage of internally generated cash flows compared to these financial obligations is a primary indicator of financial integrity and is relied upon by rating agencies when they assign debt ratings.

Q. Why is financial integrity important to Tampa Electric and its customers?

A. As a regulated utility, Tampa Electric has an obligation to provide electric service to customers in accordance with its tariff, and the statutes and rules regulating its activities. Meeting customer demand for electric service requires the company to make significant investments in utility property, plant, and equipment, both planned and unplanned, which makes Tampa Electric very capital intensive. Tampa Electric expects to invest almost $3 billion dollars to serve customers from January 1, 2024, to December 31, 2025.

Tampa Electric's customers benefit directly from the company's infrastructure investments. For example, transmission and distribution system investments enhance service reliability by mitigating storm damage and facilitating efficient service restoration, generating fleet modernization investments improve fuel efficiency thus lowering fuel costs for customers and reducing emissions, and new technology projects improve the efficiency of the company's operations and overall customer experience. Maintaining a strong financial position allows the company to finance infrastructure investments in support of an improved system at a lower cost than would otherwise be possible.

Financial integrity is also important to ensure access to capital. Tampa Electric's responsibility to serve is not contingent upon the health or the state of the financial markets. In times of constrained access to capital and depressed market conditions, only those utilities exhibiting financial integrity can attract capital under reasonable terms providing significant and potentially critical flexibility. Tampa Electric has a limited ability to adjust the timing and amount of major capital expenditures to align with economic cycles or wait out market disruptions.

The strength of Tampa Electric's balance sheet and its financial flexibility are important factors influencing its ability to finance major infrastructure investments as well as manage unexpected events. Financial integrity is essential to supporting the company's need for capital. Tampa Electric competes in a global market for capital, and a strong balance sheet with appropriate rates of return attracts capital market investors. Financial strength and flexibility enable Tampa Electric to have ready access to capital with reasonable terms and costs for the long-term benefit of its customers.

Q. Is the company's requested revenue requirement and rate increase for 2025 needed to maintain the company's financial integrity?

A. Yes. The company's requested level of 2025 rate relief is needed to maintain the company's financial integrity indicators and other key credit metrics at levels similar to the recent levels that have supported the company's current credit ratings. Without rate relief, these metrics would substantially deteriorate in 2025, and would continue to deteriorate beyond 2025 as capital spending increases and earned returns decline. Such deterioration would not support Tampa Electric's current credit ratings and would have negative implications for the company's credit ratings, borrowing costs, and access to capital.

Q. How will the company's proposed base rate increase affect Tampa Electric's financial integrity?

A. The requested base rate increase will place Tampa Electric in a prudent and responsible financial position to fund its capital program and continue providing safe and reliable electric service to its customers. To raise the required capital, the company must be able to provide fair returns to lenders and investors commensurate with the risks they assume. Having a strong financial position will ensure that Tampa Electric has a reliable stream of external capital and will allow the company's capital spending needs to be met in a cost-effective and timely manner. Uninterrupted access to the financial markets will provide Tampa Electric with the capital it needs on reasonable terms so it can continue to improve and protect the long-term interests of its customers.

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Q. What are credit ratings and why are they important?

A. The term "credit rating" refers to letter designations assigned by credit rating agencies that reflect their independent assessment of the credit quality of entities that issue publicly traded debt securities. Credit ratings are like the grades a student receives on his or her report card – an A is better than a B letter grade – likewise a AAA is better than a BBB level credit rating.

Credit ratings reflect the informed and independent views of firms that study borrowers and market conditions and impact the interest rates borrowers must pay when accessing borrowed funds from both banks and capital markets. In general, a higher credit rating means a lower credit spread and a lower credit rating means a higher credit spread.

The credit spread is the charge added to the underlying variable rate benchmark for overnight funds in the case of short-term bank borrowing and U.S. treasury bonds in the case of long-term debt offerings. Tampa Electric invests capital to serve customers and strong debt ratings will ensure that Tampa Electric will have adequate credit quality to raise the capital necessary to meet these requirements.

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Q. Why are strong ratings important considering the company's future capital needs?

A. A strong credit rating is important because it affects a company's cost of capital and access to the capital markets. Credit ratings indicate the relative riskiness of the company's debt securities. Therefore, credit ratings are reflected in the cost of borrowed funds. All other factors being equal (i.e., timing, markets, size, and terms of an offering), the higher the credit rating, the lower the cost of funds. Companies with lower credit ratings have greater difficulty raising funds in any market, but especially in times of economic uncertainty, credit crunches, or during periods when large volumes of government and higher-grade corporate debt are being sold.

Given the capital-intensive nature of the utility industry, it is critical that utilities maintain strong credit ratings sufficiently above the investment grade threshold to retain uninterrupted access to capital. The impact of being investment grade versus non-investment grade is material. A company raising debt that has non-investment grade ("speculative grade") credit ratings will be subject to occasional lapses in availability of debt capital, onerous debt covenants and higher borrowing costs. In addition, companies with non-investment grade ratings are generally unable to obtain unsecured commercial credit and may have to provide collateral, prepayment, or letters of credit for certain contractual agreements.

Given the high capital needs, obligation to serve existing and new customers, and significant requirements for unsecured commercial credit that electric utilities have, non-investment grade ratings are unacceptable. Tampa Electric’s current ratings should also be strong enough to buffer against the costs of tropical windstorm and hurricane events.

Q. Can the financial credit market be foreclosed by unforeseen events extraneous to the utility industry?

A. Yes. There have been times when financial credit markets have been closed or challenged due to unforeseen events. Market instability resulting from the sub-prime mortgage problems affected liquidity in the entire financial sector causing a financial recession, and there were periods of time in 2008 and 2009 when the debt markets were effectively closed to all but the highest rated borrowers. This is a good example of how access to the marketplace can be shut off for even creditworthy borrowers by extraneous, unforeseen events, and it emphasizes why a strong credit rating is essential to ongoing, unimpeded access to the capital markets.

Q. How are credit ratings determined?

A. Generally, the process the rating agencies follow to determine ratings involves an assessment of both business risk and financial risk. Business risk is typically determined based on the combined assessment of industry risk, country risk, and competitive position. Financial risk is based on financial ratios covering cash flow/leverage analysis. These two factors are combined to arrive at an overall credit rating for a company. Business risk and financial risk are more fully discussed and described in the direct testimony of Mr. D'Ascendis.

Q. How does regulation affect ratings?

A. The primary business risk the rating agencies focus on for utilities is regulation, and each of the rating agencies have their own views of the regulatory climate in which a utility operates. The exact assessments of the rating agencies may differ but the principles they rely upon for their independent views of the regulatory regime are

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similar. Essentially, the principles, or categories, that shape the views of the rating agencies as they relate to regulation are based upon the degree of transparency, predictability, and stability of the regulatory environment; timeliness of operating and capital cost recovery; regulatory independence; and financial stability.

According to the rating agencies the maintenance of constructive regulatory practices that support the creditworthiness of the utilities is one of the most important issues rating agencies consider when deliberating ratings. Regulation in Florida has historically been supportive of maintaining the credit quality of the state's utilities, and that has benefited customers by allowing utilities to provide for their customers' needs consistently and at a reasonable cost. This has been one of the factors that has helped Florida utilities maintain pace with the growth in the state, which has been essential to economic development. A key test of regulatory quality is the ability of companies to earn a reasonable rate of return over time, including through varying economic cycles, and to maintain satisfactory financial ratios supported by good quality of earnings and stability of cash flows. Regulated utilities cannot materially improve or even maintain their financial condition without regulatory support. Thus, the regulatory climate has a large impact on the company, its customers, and its investors.

Q. What are recent concerns expressed by any of the rating agencies for the industry?

A. Most recently, in February 2024, S&P Global's Outlook for the entire North American regulated utilities industry changed from stable to negative. S&P Global states credit quality for investor-owned utilities has weakened over the past four years with about 28 percent of the industry having a negative outlook. Their view is the industry faces rising physical risks and high cash flow deficits that may not be sufficiently funded in a credit-supportive manner. S&P Global is concerned with the strained financial cushion of the industry as it provides limited ability to absorb unexpected events such as changes to inflation, higher interest rates and other physical risks.

Q. How is Tampa Electric's long-term debt currently rated?

A. Tampa Electric's senior unsecured debt is currently rated A3 with a Negative Outlook by Moody's Investors Service

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("Moody's"), BBB+ with a Negative Outlook by S&P Global Ratings ("S&P") and A with a Negative Outlook by Fitch Ratings ("Fitch").

Q. Why is it so important to maintain an "A-" level rating on balance from all three rating agencies?

A. Maintaining Tampa Electric's current ratings is very important for two reasons.

First, Tampa Electric is making capital investments to serve customers and strong debt ratings ensure Tampa Electric has adequate credit quality to raise the capital necessary to meet these requirements.

Second, Tampa Electric's current ratings provide a reasonable degree of assurance that ratings will not slip below investment grade in the event of a hurricane or other significant weather event.

Approximately 40 percent of the utility industry is presently rated A- or above. Tampa Electric's split ratings equate to this rating level on balance and would be viewed positively regardless of an investor's preference among the rating agencies. Directionally, the A- and BBB+ rating categories represent approximately 60 percent of all utility industry ratings split relatively evenly between the two categories.

Tampa Electric’s access to capital markets and cost of financing, including the applicability of restrictive financial covenants, are influenced by the ratings of its securities.

Q. Are credit ratings impacted by equity ratio and return on equity?

A. Yes. Rating agencies pay keen attention to equity ratio and ROE when evaluating the company’s financial integrity and assigning credit ratings.

Q. What equity ratio and ROE does Tampa Electric propose in this proceeding?

A. The company’s proposed financial equity ratio is 54.0 percent. Financial equity ratio refers to investor sources of capital, for which the company is proposing 46 percent debt and 54 percent common equity. This proposed 54.0 percent equity ratio is consistent with the ratio approved by the Commission in Tampa Electric’s last general base rate proceeding.

The company's proposed midpoint ROE is 11.5 percent with an earnings range of plus or minus 100 basis points. Our proposed midpoint ROE and range are fair and reasonable, and are supported in the prepared direct testimony of Mr. D'Ascendis.

Q. Is Tampa Electric's proposed equity ratio of 54.0 percent reasonable and prudent for use in this proceeding?

A. Tampa Electric's proposed equity ratio of 54.0 percent is reasonable and prudent as it has a direct impact on the level of cash flows and the percentage of debt giving rise to the financial leverage in the capital structure, which is a key determinant of financial integrity.

Q. Why should the Commission approve the company's proposed 54 percent equity ratio?

A. Utilities in North America, including Tampa Electric, are navigating increasing physical risks and capital investment plans to continue providing safe and reliable service to its customers. Coupled with the potential for volatility in the capital markets, this warrants a stronger

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balance sheet to deal with an uncertain macro environment. A conservative financial profile, in the form of a reasonable equity ratio, is consistent with the need to accommodate these uncertainties and maintain the continuous access to capital under reasonable terms that is required to fund operations and necessary system investment, even during times of adverse capital market conditions. A downward change to the company's equity ratio would be considered credit-negative by rating agencies.

Q. Please summarize the relationship of financial integrity and the company's proposed capital structure.

A. Maintaining a strong, prudent, and responsible financial position, or financial integrity, will allow Tampa Electric to attract capital on reasonable terms and continue to provide a safe and reliable electric system for its customers. Financial integrity helps ensure uninterrupted access to capital markets to finance required infrastructure investments as well as to manage unforeseen events. Tampa Electric's rate increase request, which includes the continued appropriate levels of ROE and equity ratio, will maintain the company's financial integrity and place Tampa Electric in an appropriate financial position to fund capital costs for assets and continue providing the high level of reliable service to its customers.

(3) CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL

Q. What are the company's proposals for the specific components of capital structure and weighted average cost of capital calculations being proposed by the company in this filing?

A. The company's proposals for these components are presented below.

<u>LONG TERM DEBT</u>

Q. What amount and cost rate should be approved for long-term debt for the projected 2025 test year capital structure?

A. The Commission should approve Jurisdictional Adjusted amount of Long-Term Debt and the cost rate of $3.536 billion and 4.53 percent, respectively, as shown on MFR Schedule D-1a.

<u>SHORT TERM DEBT</u>

Q. What amount and cost rate should be approved for short term debt for the projected 2025 test year capital structure?

A. The Commission should approve Jurisdictional Adjusted amount of Short-Term Debt and the cost rate of $376.6 million and 3.90 percent, respectively, as shown on MFR Schedule D-1a.

Q. How are amounts for long term debt and short-term debt forecasted and why are they reasonable?

A. The amounts for long-term and short-term borrowings are forecasted in the budget process described in the testimony of Mr. Latta. In general, we forecast borrowing needs based on the combination of budgeted capital expenditures net of forecasted cash from operations and the company's adherence to the capital structure described in my testimony above (46 percent debt, 54 percent equity), which is needed to maintain financial integrity. The amounts are reasonable because they are determined using prudent forecasting of capital expenditures and cash from operations, and the application of Tampa Electric's commitment to capital structure ratios that are needed to keep overall cost of capital low based on factors described in my testimony above.

Q. How are cost rates for long term debt and short-term debt forecasted and why are they reasonable?

A. The cost rates for long term and short-term debt are forecasted based on the combination of (a) the actual cost rates for long term debt instruments actually in place, together with the forecasted rate for any budgeted long term borrowing at the interest rate estimated for that point in time, and (b) the forecasted rate for budgeted short term borrowings at the interest rates estimated for each month in the budget period. The cost rates are reasonable estimates based on Tampa Electric's financial integrity, credit ratings and forecasts for future market rates.

Q. Why are forecasted market rates higher than market rates at the time of the last rate proceeding?

A. In 2021, the Federal Reserve rate was 0.08 percent at year end and increased to 5.33 percent by the end of 2023.

This increase was reflected in an average short-term debt interest rate for the company of 0.58 percent in 2021, which increased to 5.70 percent in 2023. The company's actual short-term cost rate in 2022 was 2.30 percent; our forecasted short-term cost rate for 2025 is 3.90 percent.

Our actual long-term cost rate in 2022 was 4.36 percent and our forecasted long-term cost rate for 2025 is 4.53 percent. The 17-basis point increase in the long-term debt interest rate is less than the increase in the short-term debt interest rate because most of the company's 2022 long-term debt will still be outstanding in 2025.

Q. Are the cost rates in the 2025 test year at the elevated levels that were present in 2023, and if not, why is that reasonable?

A. The forecasted 2025 short term debt cost rate of 3.90 percent is lower than the 5.70 percent in 2023. It is reasonable to use a lower interest rate forecast because the rise in interest rates has begun to subside, and Tampa Electric predicts that short term rates will be lower in 2025. The forecasted 2025 long term debt cost rate is reasonable because it reflects (a) imbedded existing cost rates, (b) cost rates for the long-term debt assumed by Tampa Electric previously assigned to PGS, and (c) the 4.90 percent cost rate on the actual long-term debt issuance made in January 2024 for $500 million.

CUSTOMER DEPOSITS

Q. What amount and cost rate should be approved for customer deposits for the projected 2025 test year capital structure?

A. The Commission should approve Jurisdictional Adjusted amount of Customer Deposits and the cost rate of $99.2 million and 2.41 percent, respectively, as shown on MFR Schedule D-1a.

Q. How is the amount and cost rate for customer deposits forecasted and why are they reasonable?

A. The budgeted balances for customer deposits are calculated by using an assumed average percent for expected new deposits and released deposits associated with forecasted customers and accounts receivable. This is reasonable as it reflects a consistent application of long-standing budget process steps. The cost rate for customer deposits reflect rates approved by the Commission and is reasonable to forecast based on the infrequent number of changes made to these rates by the Commission over time.

<u>EQUITY RATIO</u>

Q. What equity ratio should be approved for the projected 2025 test year capital structure?

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A. The Commission should approve the equity ratio of 46.88 percent shown on MFR Schedule D-1a. This Jurisdictional Adjusted ratio reflects the financial equity ratio of 54.0 percent that I previously discussed.

RETURN ON EQUITY

Q. What return on equity should be approved for the projected 2025 test year capital structure?

A. As discussed in the testimony of Mr. D'Ascendis, the Commission should approve the return on equity of 11.50 percent shown on MFR Schedule D-1a.

EQUITY ADJUSTMENTS

Q. Has the company made the proper adjustments to remove all non-utility investments from the projected test year common equity balance?

A. Yes. These adjustments are shown on MFR Schedule D-1b.

DEFERRED INCOME TAXES

Q. What amount should be approved for accumulated deferred income taxes (ADIT), shown as "Deferred Income Taxes" on MFR Schedule D-1a, for the projected 2025 test year capital structure?

A. The Commission should approve Jurisdictional Adjusted amount of Deferred Income Taxes of $980.9 million as shown on MFR Schedule D-1a. Ms. Strickland explains in her testimony the method used to forecast this amount and why this amount is reasonable. ADIT is considered a zero-cost source of capital in our capital structure.

TAX CREDITS – WEIGHTED COST

Q. What amount and cost rate should be approved for unamortized investment tax credits, shown as "Tax Credits – Weighted Cost" on MFR Schedule D-1a, for the projected 2025 test year capital structure?

A. The Commission should approve Jurisdictional Adjusted amount of Tax Credits – Weighted Cost and the cost rate of $211.7 million and 8.26 percent, respectively, as shown on MFR Schedule D-1a. Ms. Strickland explains in her testimony the method used to forecast this amount and why this amount is reasonable. The cost rate is reasonable since it reflects the weighted cost of investor sources of capital, which has been the Commission-approved method for calculating the cost rate for deferred taxes subject to normalization.

CAPITAL STRUCTURE AND WEIGHTED AVERAGE COST OF CAPITAL

Q. What amount and Weighted Average Cost of Capital (WACC) for projected total capital structure should be approved for the projected 2025 test year?

A. The Commission should approve the Jurisdictional Adjusted amount of capital structure and the WACC of $9.798 billion and 7.37 percent, respectively, as shown on MFR Schedule D-1a.

(4) FUTURE FINANCIAL PROJECTIONS AND REGULATORY OPTIONS

Q. How do you expect the company's financial profile to change after 2025?

A. The company will continue to invest in assets that enhance the reliability, resilience and efficiency of our operations and serve our customers. Tampa Electric expects to spend approximately $1.6 billion each year in 2026 and 2027. In the direct testimony of Mr. Latta, he provides details on important capital projects for solar generation, other generation enhancements, storage capacity and grid infrastructure. For these projects, Mr. Latta presents the company's request for SYA in 2026 in the amount of $100.1 million and in 2027 of $71.8 million.

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As noted in the testimony of other witnesses, these projects will (a) improve the efficiency, sufficiency, and adequacy of the company's facilities and services, (2) make efficient use of alternative energy resources, (3) increase the value of the company's services to its customers, (4) promote the public interest by developing renewable resources in Florida, (5) improve the reliability and resilience of the company's operations, (6) enhance our ability to respond to severe weather, (7) create greater opportunities for fuel cost savings, and (8) improve the overall quality of our electric service.

Q. How will the 2026 and 2027 SYA impact the company's financial profile and integrity after 2025?

A. Absent the additional rate relief in 2026 and 2027 from the SYA, the plant additions referred to above will put pressure on our ability to earn within the range of ROE the company is proposing in this proceeding. Without the 2026 and 2027 SYA, Tampa Electric expects to earn below the bottom of our proposed range of equity returns in 2026 and 2027.

Q. How do customers benefit from the use of these SYA?

A. The SYA will help extend the life of the base rates approved in this proceeding and will mitigate the need for successive rate increase requests in 2026 and 2027.

Q. Does the company propose to recover general expense increases and routine capital additions through its proposed 2026 and 2027 SYA?

A. No. The specific costs to be recovered through the proposed SYA are detailed by Mr. Latta in his testimony.

Q. Are there other tools that can help extend the file for the new 2025 base rates approved in this proceeding?

A. Yes. Tampa Electric also requests approval of a corporate income tax change provision, a storm cost recovery provision and an asset optimization mechanism.

Q. What is the company's proposal to address potential corporate income tax change?

A. The company's proposal for addressing corporate income tax change is the method presented in Section 11 in the 2021 Agreement, Document No. 2 of my exhibit. This tax reform provision, and others like it in previous agreements, have served the company and its customers well by providing an efficient regulatory mechanism for addressing corporate income tax changes that occur after a rate proceeding is over.

Q. What is the company's proposal to address storm cost recovery?

A. The company's proposal for addressing storm cost recovery is the method presented in Section 8 in the 2021 Agreement, Document No. 2 of my exhibit. This Storm Cost Recovery provision, and others like it in previous agreements, have served the company and its customers well by providing an efficient regulatory mechanism for review and recovery of prudent storm damage restoration and recovery costs.

Q. What is the company's proposal for an asset optimization mechanism?

A. The company's proposal for an asset optimization mechanism is presented and discussed in the direct testimony of Tampa Electric witness John Heisey and should be approved for the reasons in his testimony.

(5) SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony describes how the company's financial profile has changed since our last rate case, including the growth in plant in service and the corresponding growth in operating expenses. I also propose SYA for 2026 and 2027 as well as tax reform and storm cost methodologies that, if approved in this case, would substantially reduce our need to seek an additional general base rate increase before 2028.

Since our last rate case, Tampa Electric has continued to transform the company into a safer and more reliable electric utility. We are customer-focused, and our generating fleet is more resilient and more efficient than ever. These changes have also transformed the company's financial profile. It is important to maintain the financial integrity of the company to enable us to meet the growing and changing energy needs in our service territory.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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(Whereupon, Volume II prefiled direct testimony of Jeff Chronister was inserted.)

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI
IN RE: PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

PREPARED DIRECT TESTIMONY AND EXHIBIT
OF
JEFF CHRONISTER
VOLUME II

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

JEFF CHRONISTER

VOLUME II

Q. Please state your name, address, occupation, and employer.

A. My name is Jeff Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Vice President Finance.

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

A. I am responsible for maintaining the financial books and records of the company and for the determination and implementation of accounting policies and practices for Tampa Electric. I am also responsible for budgeting activities within the company, which includes business planning and financial planning & analysis, as well as general accounting, regulatory accounting, plant accounting, tax accounting, financial reporting, accounts payable and payroll.

Q. Please summarize your educational background and business experience.

A. I graduated from Stetson University in 1982 with a Bachelor of Business Administration degree in Accounting. I became a Certified Public Accountant in the State of Florida in 1983. Upon graduation I joined Coopers & Lybrand, an independent public accounting firm, where I worked for four years before joining the company in 1986. I started in Tampa Electric’s Accounting department, moved to TECO Energy’s Internal Audit department in 1987, and returned to the Accounting department in 1991. I have led Tampa Electric’s Accounting department since 2003, and I led the Peoples Gas Accounting department from 2009 to 2018. I became Vice President Finance for Tampa Electric in 2018.

For the last six years, I have been responsible for treasury and finance functions, including short-term and long-term debt, cash management and debt compliance. In addition, my team works with Emera financial personnel on debt issuances, and preparation of financial information and communications for credit rating agencies and investment analysts.

Q. Have you previously testified before the Florida Public

Service Commission ("FPSC" or the "Commission")?

A. Yes. I have testified or filed testimony before this Commission in several dockets.

I testified for Tampa Electric in Docket No. 20210034-EI, which was Tampa Electric's last base rate proceeding.

I filed testimony in the following dockets:

(1) Docket No. 20130040-EI, Tampa Electric Company's Petition for An Increase in Base Rates and Miscellaneous Service Charges;

(2) Docket No. 20080317-EI, Tampa Electric Company's Petition for An Increase in Base Rates and Miscellaneous Service Charges;

(3) Docket No. 19960007-EI, Tampa Electric's Environmental Cost Recovery Clause;

(4) Docket No. 19960688-EI, Tampa Electric's environmental compliance activities for purposes of cost recovery;

(5) Docket No. 20170271-EI, Petition for recovery of costs associated with named tropical systems during the 2015, 2016, and 2017 hurricane seasons and replenishment of storm reserve subject to final true-up; and

(6) Docket No. 20200144-EI, Petition for Limited Proceeding to True-Up First and Second SoBRA by Tampa Electric Company.

I also served on a panel of witnesses during the final hearing in Docket No. 20200065-EI, which addressed the company's amortization reserve for intangible software assets.

Q. What are the purposes of Volume II of your direct testimony?

A. The purposes of Volume II of my direct testimony are to describe the company's 2025 test year; explain our 2025 budget and the process we used to develop it; present our proposed 2025 rate base, net operating income, and revenue requirement increase; explain how the company accounts for affiliated transactions; and present the revenue requirement calculations for the company's proposed 2026 and 2027 Subsequent Year Adjustments ("SYA").

Q. Have you prepared an exhibit to support Volume II of your direct testimony?

A. Yes, Exhibit JC-2, entitled the "Exhibit of Jeff Chronister

2", was prepared under my direction and supervision. The contents of my exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. It consists of five documents, as follows:

Document No. 1	List of Minimum Filing Requirement Schedules Sponsored or Co-Sponsored by Jeff Chronister
Document No. 2	2019-2025 Budgeted Versus Actual Jurisdictional Adjusted Rate Base
Document No. 3	2022-2025 Total Company Capital Investments
Document No. 4	2022-2025 Total O&M Expense
Document No. 5	2026 and 2027 Subsequent Year Adjustment (SYA) Details

Q. Do you sponsor any sections of Tampa Electric's Minimum Filing Requirement ("MFR") Schedules?

A. Yes. I sponsor or co-sponsor the MFR Schedules listed in Document No. 1 of my exhibit. The contents of these MFR Schedules were derived from the business records of the company and are true and correct to the best of my information and belief.

Q. How does Volume II of your direct testimony relate to the testimony of other Tampa Electric witnesses in this case?

A. Volume II of my direct testimony explains the budget process and why using a projected 2025 test year is appropriate in this case.

Tampa Electric witness Lori Cifuentes presents the customer, energy sales, and peak demand forecasts that form the basis for the budget underlying the financial information for our 2025 test year.

Volume II of my direct testimony also presents the company's overall 2025 revenue requirement calculation. Other witnesses discuss specific parts of our revenue requirement. For example, Tampa Electric witness Ned Allis discusses our depreciation study and supports our requested level of depreciation expense and capital recovery amortization in the test year. Tampa Electric witness Dylan D'Ascendis presents the company's proposed return on equity. Other witnesses address specific components of our rate base, show that our proposed plant additions are reasonable and prudent, and demonstrate that our operations and maintenance ("O&M") expenses are reasonable. Tampa Electric witness Valerie Strickland presents the company's

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income tax expense calculation and proposed parent debt adjustment.

My direct testimony filed on April 2, 2024 (hereinafter "Original Prepared Direct Testimony"), discusses how our financial profile has changed since our last rate case; all elements of our capital structure, and our proposed overall rate of return; presents information about our financial forecasts for 2026 and 2027; and proposes that the Commission approve subsequent year adjustments in those years.

Q. Other than describing your background, explaining the purposes of Volume II of your direct testimony, and explaining how Volume II relates to other direct testimony filed in this case, is the remainder of your testimony the same as that set forth in the Direct Testimony of Richard Latta that was filed in this proceeding on April 2, 2024?

A. Yes, except for one set of changes. Mr Latta's original testimony referred to "Mr. Chronister's testimony" in several places. I changed these references to refer to my Original Prepared Direct Testimony.

(1) 2025 TEST YEAR

Q. What test year has the company used to prepare its MFR and 2025 rate increase request?

A. The company's test year for its proposed 2025 increase is the calendar year ending December 31, 2025.

Q. Should the Commission approve the company's proposed 2025 test year for ratemaking purposes in this case?

A. Yes. The company's proposed test period of the twelve months ending December 31, 2025 is appropriate because (1) 2025 is the first year the company's proposed rates are proposed to be in effect and (2) the company's financial budget for that period is representative of Tampa Electric's projected revenues and projected costs of service, capital structure, and rate base needed to provide safe, reliable, and cost-effective electric service to its customers in 2025. The company's budgeting process is reliable and the resulting 2025 budgets are more representative of the company's operations when its proposed rates will be in effect than a historical test year.

Q. What does the company project its 2025 earned return on equity to be without the 2025 rate increase requested in this case?

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A. Without our 2025 requested rate increase, the company's projected earned return on equity ("ROE") for 2025 is expected to be 6.70 percent, which is far below the fair and reasonable range of equity returns supported in the direct testimony of Mr. D'Ascendis.

The company has invested in infrastructure that provides value to customers and fulfills our obligation to provide reliable and resilient utility service; however, revenue growth has not kept pace with the growth of our rate base assets, causing our projected ROE in 2025 to fall below the level needed to maintain Tampa Electric's financial integrity. The company's need to maintain financial integrity is discussed further in my Original Prepared Direct Testimony filed on April 2, 2024.

Q. When does the company propose that its new 2025 base rates and charges become effective?

A. Tampa Electric proposes that its new 2025 base rates and charges become effective for the first billing cycle in January 2025. We also propose that the Commission approve two SYA to recover the costs associated with certain projects to be effective with the first billing cycles in 2026 and 2027. I discuss these SYA in the last section of my testimony.

(2) 2025 BUDGET AND BUDGET PROCESS

Q. Please describe the process Tampa Electric used to prepare its 2025 test year budget.

A. We prepared the 2025 budget using an integrated process that combined the goals and objectives of the company with expected economic and financial conditions. We developed plans for projects and activities based on the company's obligation to serve, and expectations of the requirements and challenges associated with that obligation.

We developed these plans for projects and activities within each department and then consolidated them into overall company projections. Each department quantified its projects and activities into specific required work in its respective budgets. This process is described in more detail in MFR Schedules F-5 (Forecasting Models) and F-8 (Assumptions). The models we used and the assumptions we made as part of the budgeting process are reasonable for managing our operations and for ratemaking purposes in this case.

Tampa Electric's budget process incorporates the American

Institute of Certified Public Accountants guidelines for preparing prospective financial information. The company's budgeting process conforms with all of the guidelines, including those related to quality, consistency, documentation, the use of appropriate accounting principles and assumptions, the adequacy of review and approval, and the regular comparison of financial forecasts with attained results.

Q. Was the budgeting process for 2025 different than the budgeting process used in Tampa Electric's last rate case?

A. No. Although the technology the company uses to prepare budgets has evolved over time, we have not changed the basic process we used to build our budgets. We based our 2025 budget on expected operating conditions. We relied on the experience and expertise of the company's operating teams. Our front-line operating personnel and members of management collaborated to forecast projects and activities, and their corresponding costs. Our 2025 budget is consistent with and reflects our long-term planning, prioritizes our resource needs, and reflects operating efficiencies where available. Our operating personnel also forecasted the level of 2025 other operating revenues that reduces the overall 2025 revenue

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requirement.

Q. Did the company prepare its budget for the 2025 test year using the company's normal annual budget process described above?

A. Yes. The process described above reflects our normal budgeting process except for the time schedule for preparing it, which was accelerated as a practical necessity of filing a rate case with a projected test year.

Q. What primary economic and financial conditions did the company consider when developing its 2025 budget?

A. We considered the following: (1) the impact of load growth, which includes changes in the number of customers and usage per customer and (2) the impact of inflation, contract escalations, and other cost changes. Our 2025 budget was based on the company's Customer, Demand, and Energy forecasts, which are explained in the direct testimony of Ms. Cifuentes. The company used a variety of indices and factors to estimate the effects of inflation and cost changes in the 2025 budget.

Q. What basic documents does the company's budget process

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produce?

A. Our integrated budget process generated a complete set of budgeted financial statements for 2025: income statement, balance sheet, and statement of cash flows. We constructed the income statement using various sources to forecast revenues and expenses. We created the balance sheet by starting with beginning balances and either forecasting monthly balances for the remainder of the year or forecasting monthly activity in the account for the remainder of the year, depending on the type of account. Then we prepared a statement of cash flows to determine the capital structure needs of the company and the required debt and equity needed during the budget year.

Q. Please describe the most material components in the company’s 2025 budgeted financial statements.

A. Our budgeted 2025 balance sheet is the foundation for our calculation of budgeted 2025 rate base and capital structure. The largest component of our 2025 budgeted rate base is net utility plant-in-service. Plant-in-service balances reflect the capital expenditures for property, plant, and equipment already invested as well as the capital investments contained in the near-term capital budget, all of which will be utilized to serve our customers in 2025. Capital structure supports our rate base investments using debt, equity and other sources.

Our budgeted 2025 income statement is the foundation for our calculation of budgeted 2025 net operating income. It begins with our revenue budget and reflects the major expense elements that are recoverable through base rates.

With the exception of O&M for fuel and purchase power expenses, which are predominantly recovered through the fuel and purchased power and capacity cost recovery clauses, which are not a subject in this proceeding, the largest cost component of the 2025 budgeted net operating income is depreciation expense, which is calculated based on projected plant balances and applicable depreciation rates. Other O&M expense, taxes other than income and income tax expenses are also major portions of our net operating income. Our budgeted 2025 income statement reflects our generation planned outage schedule, our clause budgets and our revenue budget for the test year.

Q. How did the company develop its 2025 revenue budget?

A. The company prepared the revenue budget by applying its current tariff rates to electricity sales reflected in the Customer, Demand, and Energy forecasts by customer rate class. The company prepared detailed revenue projections by month using present rates and included the monthly data in the income statement.

Q. Please discuss the Customer, Demand, and Energy forecasts used to develop the company's revenue budget.

A. The Load Research and Forecasting section of the company's Regulatory Affairs department produced the 2025 Customer, Demand, and Energy forecasts, which reflects customer growth projections as well as load and consumption projections. Ms. Cifuentes is responsible for this function and discusses key assumptions used to develop the forecasts in more detail in her direct testimony. Tampa Electric witness Jordan Williams applies the present rates to the results of the Customer, Demand, and Energy forecast to develop the revenues from the sales of electricity.

Q. Is the company's 2025 budgeted revenue from the sales of electricity by rate class at present rates appropriate?

A. Yes. The Commission should approve $1,480,725,000 as the company's 2025 revenues from the sale of electricity. This amount is shown on MFR Schedule C-1.

Q. How did the company forecast the other operating revenues for 2025?

A. We use different approaches to forecast different components of Other Operating Revenue. We budget miscellaneous service revenues using a customer growth rate, because these revenues vary with customer growth and activity. We forecast other rent revenues using the terms of contracts, such as pole attachment agreements. We budget other items, such as revenues from barge cleaning or use of our loading facilities on an item-specific basis.

Q. Please describe the company's O&M and capital budgeting process.

A. Based on forecasted demand and energy, Tampa Electric determined the required capital investment necessary to serve the load reliably as well as the O&M needed to provide the quality of service customers expect. The company considered factors such as environmental and regulatory compliance, reserve requirements, and other items such as load location, changes in equipment and technology, and changes in required skill sets. These other items are discussed by Tampa Electric witnesses Carlos Aldazabal, Kris Stryker, Chip Whitworth, Karen Sparkman, David Lukcic, Chris Heck, and Marian Cacciatore in greater detail. After determining the projects and activities needed to improve the efficiency, sufficiency, and adequacy of the company's facilities, and to provide, safe, reliable, and resilient service to our customers, we estimated associated costs based on the resources to be used and the price of those resources.

The company used different tools to determine the costs of the resources needed based on the type of resource. For example, as described in the direct testimony of Ms. Cacciatore, the compensation amounts reflected in our 2025 budget were set based on expected job market conditions and market assessment and comparison tools.

Q. How did the company develop its detailed O&M and capital budgets?

A. Each operating department within the company developed detailed budgets for O&M and capital by month. Operating departments distinguished between O&M and capital based on the nature of the activity involved and our accounting policies and practices. Each operating department weighed options regarding how to perform O&M and capital work in the most cost-effective manner, and then submitted a detailed operating budget to the Finance department.

The Finance department combined all of these budgets and data to produce a total projected amount of O&M and capital expenditures for the company. The activities and projects that are necessary to provide safe and reliable service to customers were planned by the departments that perform them, and the costs were developed using consistent assumptions. The officers of the company examined the budgets for reasonableness and consistency with our overall corporate objectives and initiatives. Finally, the budget was approved by the Board of Directors.

Q. What non-labor trend factors should be used for inflation for the 2025 projected test years?

A. Non-labor O&M was held constant at 2023 levels except for some specific needs such as timing of planned outages, expanded solar operations, digitalization of the customer experience, cyber security costs and some contractor costs in the distribution function to support customer growth.

Q. Has Tampa Electric's budgeting process proven reliable in

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the past?

A. Yes. MFR Schedule C-6 and Document No. 2 of my exhibit show that our actual results have closely tracked budgeted Net Operating Income and Rate Base amounts. Our capital expenditures for the last four years have come in 1.6 percent higher, 0.1 percent higher, 13.7 percent higher and 1.6 percent higher than budgeted amounts.

Tampa Electric devotes significant effort to ensure our budgeting process is reliable because the company uses its budgeted information for investor presentations, business planning, and key decision-making. We also prepare and analyze budget variance reports and use these monthly analyses as part of the internal control system to manage our business and comply with the Sarbanes-Oxley Act of 2002.

Q. Did the budgeting process that Tampa Electric used generate a fair and reasonable projection of the company’s projected 2025 financial condition for use in this proceeding?

A. Yes. Tampa Electric used its reasonable, reliable, and time-proven budgeting process to produce its 2025 company budget.

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(3) 2025 RATE BASE

Q. Is the 2025 rate base that supports the revenue requirement calculation reasonable and prudent and reflect the assets expected to be used and useful and in service in 2025?

A. Yes. The company's projected 13-month average rate base amount for the 2025 test year is $9.8 billion as shown on MFR Schedule B-1. This projected rate base reflects appropriate amounts of net plant-in-service and working capital budgeted in the company's budgeted balance sheet. Tampa Electric projects the amount of rate base in the 2025 test year that is needed for reasonable, prudent investments and spending on assets that are used and useful in providing reliable electric service to our customers. My Original Prepared Direct Testimony and the testimony of Tampa Electric witnesses Whitworth, Stryker, Aldazabal, Lukcic, Heck, Sparkman, and Aponte address specific portions of our rate base growth in their direct testimony and explain why our rate base amounts for the 2025 test year are reasonable. Our Jurisdictional Adjusted Rate Base reflects reasonable amounts for adjustments previously approved by the Commission, and should be approved.

Q. How much capital did the company invest during the three-

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year term of the 2021 Agreement from 2022 through 2024?

A. From 2022 to 2024, the company expects to invest approximately $3.7 billion in capital projects to serve new customers; improve reliability, resilience, and efficiency; and ensure that our existing plant investments remain in sound working condition.

Approximately $2.2 billion of these investments are base rate projects that earn Allowance for Funds Used During Construction ("AFUDC"), projects for which cost recovery occurs through a cost recovery clause ("Clause projects"), and non-utility projects which are not included for recovery in this proceeding.

The remaining approximately $1.5 billion of capital expenditures for 2022 to 2024 are explained in the direct testimony of Mr. Aldazabal, Mr. Stryker, Mr. Whitworth, Mr. Lukcic, Ms. Sparkman, and Mr. Heck for their areas of responsibility.

My testimony addresses the portion of 2022 to 2024 capital expenditures that are considered "corporate."

Document No. 3 of my exhibit reflects (1) total company capital spending, (2) AFUDC and Clause capital spending, and (3) the net "base rate" capital spending by witness for 2022 to 2024 in total and by year.

Q. How much capital in other corporate investments will the company invest from 2022 through 2024?

A. The company expects to invest approximately $37.2 million in general corporate projects during that period. About half of that amount is attributable to capital projects needed to maintain buildings, such as roofing, flooring and air condition replacements. We expect to spend about a quarter of that amount on safety items such as an access control system replacement and physical safety enhancements at critical locations like our power plants. Roughly a quarter is for upgrades and enhancements to our financial and resource systems, which support our human resource, supply chain and finance functions. The upgrades are needed to keep the systems current and operational and will also improve the functionality and efficiency of the systems.

Q. How much total capital does the company expect to invest in 2025?

A. The company expects to make capital investments of $1.6 billion in 2025. $1.0 billion of these investments are AFUDC, Clause, and Non-Utility projects that are not included for 2025 base rate recovery in this proceeding. Document No. 3 of my exhibit reflects the (1) total company capital spending, (2) AFUDC and Clause capital spending, and (3) the net "base rate" capital spending by witness for 2025.

Q. What major Other Corporate projects are planned for 2025?

A. In 2025, we plan to spend approximately $17.5 million on Other Corporate projects. Approximately half of this amount will be facility-related investments like a building controls system upgrade and an underground tank replacement at the Ybor Data Center to fuel the emergency generator.

We will continue to invest in safety with projects like gate installations/replacements, thermal system implementation, and NERC substation security to protect critical assets. We will also be upgrading our PowerPlan system, which is part of our financial and resource systems, is used to account for approximately $15.0 billion of plant in service, and provides critical support

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for tax and regulatory compliance.

Q. Did the company make any accounting policy changes since the company's last rate proceeding that will affect rate base amounts?

A. No. Although there have been no major changes to generally accepted accounting principles ("GAAP") and no material accounting policy changes that affected Tampa Electric since 2021, it should be noted that we updated our regulatory accounting to reflect the addition of the Clean Energy Transition Mechanism ("CETM"). My Original Prepared Direct Testimony discusses how the CETM has impacted the company's financial profile and financial statement presentations.

<u>PLANT IN SERVICE</u>

Q. What level of plant in service should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Plant in Service totaling $13.4 billion, shown on MFR Schedule B-1. This balance includes the capital additions since our last rate proceeding discussed in the testimony of other witnesses and the budgeted amount of electric plant-in-service that will be used and useful to provide service to our customers in 2025.

ACCUMULATED PROVISION FOR DEPRECIATION AND AMORTIZATION

Q. What level of accumulated depreciation and amortization should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Accumulated Depreciation and Amortization totaling $4.0 billion as shown on MFR Schedule B-1. These balances include the impacts of the company's actual and projected plant balances and the company's proposed depreciation rates discussed in the testimony of Mr. Allis.

CONSTRUCTION WORK IN PROGRESS

Q. What level of construction work in progress ("CWIP") should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted CWIP totaling $230.2 million as shown on MFR Schedule B-1. This amount reflects the results of the company's budgeting process described above and is a reasonable and prudent amount of CWIP for the test year.

WORKING CAPITAL ALLOWANCE

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Q. What level of working capital should be approved for the 2025 test year?

A. The Commission should approve the Jurisdictional Adjusted Working Capital Allowance totaling $86.7 million as shown on MFR Schedule B-1. This amount was calculated using the results of the company's budgeting process and the Commission-approved balance sheet method for working capital. The amount reflects a reasonable amount of working capital to support the company's operations in 2025.

<u>ADJUSTMENTS</u>

Q. Please describe the FPSC adjustments to rate base shown in MFR Schedules B-1, B-2, B-6, and B-17.

A. The FPSC adjustments to rate base, as shown in MFR Schedules B-1, B-2, B-6, and B-17, reflect Commission directives, policies, and decisions from previous rate proceedings. These adjustments include: (1) removing the effect of items recoverable through the cost recovery clauses from net plant-in-service, (2) removing balances that earn AFUDC from CWIP, (3) removing the effect of items for which a return is provided elsewhere from working capital, such as regulatory assets for clause-related under-recovery balances, (4) removing from net plant-in-service and working capital the right-of-use assets and liabilities for lease obligations, and (5) removing the effect of items that have been deemed non-utility or non-recoverable through retail base rates from rate base.

Q. Did the company include AFUDC-eligible CWIP in rate base for the 2025 test year?

A. No.

Q. Did the company adjust coal fuel inventory per books to reflect the 13-month average of 60-day maximum coal burn standard approved in the company's last rate case?

A. No, because the projected coal inventory is below that maximum.

Q. Did the company adjust oil fuel inventory per books to reflect the maximum oil inventory approved in the company's last rate case?

A. Yes. The company made a $188,876 adjustment for this as shown on MFR Schedule B-2.

Q. What level of fuel inventory should be approved for the 2025 test year?

A. The Commission should approve Fuel Inventory totaling $36.6 million as shown on MFR Schedule B-17. The amount was calculated using a reasonable and prudent projection process that forecasts load, generation and corresponding fuel consumption, and associated fuel purchases. The amount of coal fuel inventory is below the 60-day maximum burn threshold approved by the Commission. The amount of oil fuel inventory is at the approved level. This fuel inventory level is reasonable because it is within the approved thresholds and reflects the fuel inventory necessary to support the company's operations in 2025.

Q. Has Tampa Electric made the proper adjustments to the working capital allowance to reflect the under recoveries and over recoveries related to cost recovery clauses in the 2025 test year?

A. Yes.

Q. What level of unamortized rate case expense should be included in working capital for the 2025 test year?

A. Zero. The company removed unamortized rate case expense in the amount of $1.8 million from working capital as shown on MFR Schedule B-2.

Q. Has the company made the proper adjustments to remove all non-utility activities from its 2025 test year Plant-in-Service, Accumulated Depreciation, and Working Capital balances?

A. Yes.

Q. Should any new adjustments be made to the amounts included in the 2025 test year for acquisition adjustments and accumulated amortization of acquisition adjustments?

A. No.

<u>TOTAL 2025 RATE BASE</u>

Q. Based on the foregoing answers, and after applying the adjustments described above, what level of projected 13-month average rate base should the Commission approve for the 2025 test year?

A. The Commission should approve the projected 13-month average rate base for 2025 of $9.8 billion as shown on

MFR Schedule B-1.

(4) 2025 NET OPERATING INCOME

Q. Is the 2025 net operating income that supports the revenue requirement calculation reasonable?

A. Yes. The company's proposed 2025 Net Operating Income is $501.4 million as shown on MFR Schedule C-1. This projected net operating income reflects reasonable and appropriate amounts of revenue and expense forecasted for 2025 in the company's budgeted income statement and reflects the transactions and activities the company will undertake in 2025 to provide reliable electric service to our customers.

Tampa Electric witnesses Aldazabal, Stryker, Whitworth, Lukcic, Sparkman, Heck, Cacciatore, Allis, Strickland, and my Original Prepared Direct Testimony address specific portions of our net operating income and explain why our net operating income amounts for the 2025 test year are reasonable. The Jurisdictional Adjusted net operating income shown on MFR Schedule C-1 reflects reasonable amounts for adjustments previously approved by the Commission.

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Q. Does the company have any non-utility operations that use all or part of any utility plant, that are not included in MFR Schedule C-32?

A. No.

TOTAL OPERATING REVENUES

Q. What annual operating revenue increase should be approved based on the 2025 projected test year?

A. The Commission should approve annual Total Operating Revenues increase in the amount of $296.6 million as shown on MFR Schedule A-1.

OPERATIONS & MAINTENANCE (O&M)

Q. How are the relevant proposed 2025 O&M amounts discussed below reflected in the company's MFR Schedules and your exhibit?

A. MFR Schedule C-1 (column 8) reflect Jurisdictional Adjusted Other O&M Expense of $391.8 million and Jurisdictional Adjusted Fuel Expense of $0.6 million, and total $392.4 million. Prior to Jurisdictional Separation, this amount is $394.1 million and is shown in the O&M Benchmark Comparison By Function on MFR Schedule C-37.

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Document No. 4 of my exhibit shows the portions of the total $394.1 million attributable to the other witnesses in this case.

OTHER O&M EXPENSE

Q. What level of Other O&M expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Other O&M Expense of $391.8 million as shown on MFR Schedule C-1. This amount is reasonable as discussed further in my testimony and in my Original Prepared Direct Testimony and the testimonies of Tampa Electric witnesses Aldazabal, Stryker, Whitworth, Lukcic, Sparkman, Heck, Cacciatore, Allis, and Strickland.

Q. Please discuss O&M spending through recent years.

A. Document No. 4 of my exhibit shows the breakdown of test year O&M expenses by witness over time. Although we are spending more each year to operate and maintain our growing system, our cumulative annual O&M expense growth rate over the past 10 years is only one half of one percent, which is well below customer growth and inflation. The company’s 2025 O&M expense by operational area are explained in the direct testimony of Mr. Aldazabal, Mr. Whitworth, Ms. Sparkman, Ms. Cacciatore and Mr. Heck for their areas of responsibility. I will cover the remainder ("Corporate Administrative & General"). My Original Prepared Direct Testimony also discusses O&M over time.

Q. How do these spending levels compare with what would be expected using escalation factors as calculated in the Commission's benchmark?

A. The $394.1 million amount for 2025 is well below the Commission's expected benchmark calculation of $466.0 million, which is shown on MFR Schedule C-37.

Q. What is the total amount of FPSC Adjusted O&M expense for administrative and general expenses in 2025?

A. MFR Schedule C-37 shows the total budgeted amount in 2025 is approximately $158.0 million. This amount reflects the administrative and general costs necessary to support the operations of the company in the test year, is reasonable, and should be approved.

Q. How do these administrative and general spending levels compare with what would be expected using escalation factors as calculated in the Commission's benchmark?

A. The $158.0 million is $56.0 million below the Commission's expected benchmark calculation of $214.0 million as shown on MFR Schedule C-37.

Q. What was the employee count for corporate administrative and general departments in 2022, 2023, and 2024?

A. The average employee count for corporate administrative and general departments is 257, 265, and 265, respectively.

Q. What is the projected employee count for corporate administrative and general departments for 2025?

A. The average projected employee count for corporate administrative and general departments in 2025 is 265, which is the same level as 2023 and 2024.

Q. Please discuss what is included in corporate administrative and general O&M expenses and the level of spending through recent years.

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A. Corporate administrative and general ("A&G") costs include costs for areas such as Finance, Procurement, Human Resources, Legal and Regulatory, as well as expenses for property and liability insurance, injuries and damages, and other corporate credits. Corporate credits include amounts for charges to capital and affiliates for benefits/fringe and A&G expense capitalization. Document No. 4 of my exhibit shows our Corporate Administrative and General expenses from 2022 through 2025. The company has demonstrated cost control in many of the areas listed above; however, premium increases caused by market forces in the property and casualty insurance markets have put upward pressure on our A&G expense levels.

Q. Please describe the challenges the company has experienced in property and liability insurance markets.

A. The company's insurance costs have gone up significantly in the past few years due to premium rate increases and having a larger base of assets to insure. Insurance premiums are a function of the losses incurred by carriers and the market returns carriers can earn on the premium dollars available for them to invest. Although public policy makers in Florida have recently enacted changes to moderate insurance premium increases, Tampa Electric, like homeowners and other businesses in Florida, has experienced and continues to experience increasing property insurance costs. While the company continuously monitors and manages its risk profile for assets to temper insurance cost increases, the premiums for reasonable and prudent insurance coverage have increased dramatically.

The company's actual and projected O&M expense for insurance over time is summarized below:

2017	$ 11.0 million
2018	$ 12.0 million
2019	$ 15.2 million
2020	$ 21.4 million
2021	$ 26.1 million
2022	$ 28.5 million
2023	$ 30.8 million
2024	$ 35.2 million
2025	$ 39.6 million

Q. Did the company include lobbying expenses, other political expenses, or civic/charitable contributions when it calculated net operating income for the 2025 test year?

A. No. The company excluded the budgeted amounts for these activities when it calculated 2025 net operating income.

Q. Has the company made the proper adjustments to remove the impact of cost recovery clauses from net operating income in the 2025 projected test year?

A. Yes.

Q. Has Tampa Electric made the proper adjustments to remove all non-utility activities from projected test year operating expenses, including depreciation and amortization expense?

A. Yes.

Q. What amount of economic development expenses should be approved for the 2025 projected test year?

A. The Commission should approve $446,502 of economic development expenses for the 2025 projected test year. Section 25-6.0426, Florida Administrative Code, governs how Tampa Electric reports economic development expenses for surveillance reporting purposes. Subsection (3) of that rule limits the amount of economic development expense that can be recognized for earnings surveillance reporting purposes. Subsection (4) of that rule specifies that the Commission will determine the level of sharing or prudent economic development costs and the future treatment of those costs for surveillance reporting purposes. The company removed $23,000 to comply with this rule as shown on MFR Schedule C-2.

Q. What amount of annual storm damage accrual should be approved for the 2025 test year?

A. Zero. The company has not included a storm damage accrual in its calculation of net operating income for the 2025 test year. Rather, as discussed in my Original Prepared Direct Testimony, the company proposes to extend the storm cost recovery provision in its 2021 Agreement.

Q. Is the company proposing to change its reserve target for account 228.1 (reserve for storm damages) or to implement an annual storm damage expense accrual in this case?

A. No. The current reserve target is $55,860,642 as approved in Order No. PSC-2021-0423-S-EI on November 10, 2021, in Docket No. 20210034-EI. The company is not proposing to change this amount. The last storm damage study was filed in Docket 20210031-EI and Tampa Electric is not due to file another Storm Damage Study until 2026, so the company has not filed an updated Storm Damage Study in this proceeding. Our projected reserve balance as of 2025 is $17.8 million as reflected on MFR Schedule B-3 and is less than the reserve target due to the level of storm activity in 2023. The company intends to use storm surcharges to replenish the reserve once depleted.

Q. What amount of rate case expense should be approved in this proceeding?

A. The Commission should approve rate case expense of $2.0 million and a three-year amortization period. The company has included approximately $682,537 of rate case expense in its calculation of net operating income for 2025. This amount is reasonable in light of the size of Tampa Electric, the increases requested in this case, the level of discovery activity we expect, and the complexity of the issues in the case.

Q. Does the company’s proposed level of O&M expense for the projected 2025 test year include any amounts related to potential merger and acquisition activities by Tampa Electric or any of its affiliates?

A. No.

FUEL EXPENSE

Q. What level of Fuel expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Fuel expense of $0.6 million as shown on MFR Schedule C-1. Most fuel expense ($685.5 million) is recovered through the fuel and purchased power and capacity cost recovery clauses and is adjusted on MFR Schedule C-1. The remaining $0.6 million is related to costs to oversee and operate fuel activities, such as supervising and handling of fuel, which are not recoverable through the fuel and purchased power clause.

DEPRECIATION AND AMORTIZATION

Q. What amount of depreciation and amortization expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Depreciation and Amortization expense in the amount of $531.4 million as shown on MFR Schedule C-1. This amount was calculated using the company's projected plant balances and the rates proposed in Tampa Electric's 2023

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Depreciation Study submitted on December 27, 2023, in Docket No. 20230139-EI.

Mr. Allis describes the company's proposed depreciation rates and study in detail; the Tampa Electric witness Jeff Kopp supports and explains the dismantlement study the company commissioned for inclusion in the 2023 Depreciation Study. Our 2025 budgeted income statement also reflects the levels of capital recovery amortization discussed in Mr. Allis' testimony. My Original Prepared Direct Testimony also discusses depreciation expense.

Q. What depreciation period study date should be used to calculate depreciation expense for the 2025 projected test year?

A. The projected ending plant balances as of December 31, 2024, from the depreciation study that was filed on December 27, 2023, should be used.

Q. What should be the implementation date for the revised depreciate rates, capital recovery schedules, and amortization schedules proposed by the company in this case?

A. The Commission should approve an implementation date of January 2025 for the company's proposed, revised depreciation rates, capital recovery schedules, and amortization schedules. This effective date matches our proposed effective date for our proposed new 2025 customer rates.

<u>TAXES OTHER THAN INCOME</u>

Q. What level of Taxes Other Than Income expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Taxes Other than Income ("TOTI") expense of $101.6 million as shown on MFR Schedule C-1. This amount is reasonable as it was forecasted using prudent estimates of property values and assessments for ad valorem tax purposes. My Original Prepared Direct Testimony discusses TOTI further.

<u>INCOME TAXES</u>

Q. What level of Income Tax expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Income Tax expense (benefit) totaling ($8.3 million) as shown on MFR Schedule C-1. Ms. Strickland describes the company's income tax expense and explains why this amount is reasonable in her testimony.

Q. Please explain the income tax true up for interest synchronization.

A. After adjustments described earlier in my testimony were made to rate base, we adjusted 2025 Income Tax expense to reflect the appropriate amount of interest expense based on the amount and cost of debt in the capital structure that was synchronized to the rate base. This adjustment, as shown on MFR Schedule C-3, was done in accordance with the Commission's practice, and should be approved.

Q. Did the company make a parent debt adjustment as contemplated in Rule 25-14.004, Florida Administrative Code?

A. Yes. The company's proposed adjustment is discussed further by Ms. Strickland in her testimony.

GAIN/LOSS ON DISPOSAL OF PLANT

Q. Did the company have gains or losses on the disposition of plant and property previously used to provide electric

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service?

A. No. The company does not expect to recognize any new gains or losses on the disposition of plant and property previously used to provide electric service in 2024 or 2025. The amortization of prior gains will be completed by August 2024, so the company did not include any amount for amortization of gain or loss on disposal of plant in its calculation of 2025 net operating income.

ADJUSTMENTS

Q. Please describe the FPSC adjustments the company made to net operating income as shown in MFR Schedules C-1, C-2, C-3, C-4, and C-5.

A. The FPSC adjustments to net operating income, as shown in MFR Schedules C-1, C-2, C-3, C-4, and C-5 reflect Commission directives, policies, and decisions from previous rate proceedings. These adjustments include: (1) removing the revenues and expenses which are recoverable through the cost recovery clauses and mechanisms, (2) removing franchise fee revenues and expenses, (3) removing gross receipts tax revenues and expenses, (4) the income tax true-up for interest synchronization, (5) a parent debt adjustment, and (6) removing expenses that have been deemed non-utility or non-recoverable through retail base rates. Examples of these items include stockholder relations expenses and a portion of industry association dues.

Q. Based on the foregoing, and based on these adjustments, what amount of Total Operating Expenses should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Total Operating Expenses of $1.0 billion as shown on MFR Schedule C-4.

NET OPERATING INCOME

Q. Based on the foregoing, and after applying the adjustments explained above, what amount of Net Operating Income should be approved for the 2025 Test Year?

A. The Commission should approve Jurisdictional Adjusted Net Operating Income of $501.4 million as shown on MFR Schedule C-1.

(5) 2025 REVENUE REQUIREMENT

Q. How did the company calculate the amount of the revenue requirement increase it is requesting for 2025 in this

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case?

A. We calculated our total revenue requirement as the sum of the required return on our rate base plus the costs of providing electric service, grossed up for taxes. It is shown on MFR Schedule A-1.

We calculated our requested 2025 revenue increase by comparing the projected net operating income for 2025 to the net operating income that resulted from multiplying the 2025 13-month average rate base to the 2025 weighted average cost of capital, as shown on MFR Schedule A-1.

We based our 2025 System Per Books net operating income, 13-month average rate base, and capital structure calculations, as reflected in our MFR Schedules, on Tampa Electric's 2025 budgeted Income Statement, Balance Sheet, and Statement of Cash Flows.

We then made regulatory adjustments to the system per books amounts for net operating income, rate base, and capital structure. These regulatory adjustments can include two types: (1) those that are necessary to comply with Commission directives, policies, and decisions ("FPSC adjustments") and (2) any applicable adjustments

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that are necessary to produce a test year that is indicative of ongoing revenue and expenditure levels ("company pro forma adjustments"). These adjustments are discussed in detail in the Rate Base and Net Operating income sections above. We then applied the jurisdictional separation factors, supported in the direct testimony of Mr. Williams, to derive the jurisdictional amounts upon which the revenue requirement is calculated.

The basic calculation is shown on MFR Schedule A-1. We first applied the 7.37 percent required overall cost of capital to the jurisdictional adjusted average rate base of $9.8 billion, which resulted in a required jurisdictional net operating income of $722.1 million. Comparing the required jurisdictional net operating income to the jurisdictional net operating income based on the company's 2025 projected test year of $501.4 million without a base rate increase, we calculated the net operating income deficiency for 2025 to be $220.8 million. After grossing this amount up for taxes, we computed our jurisdictional revenue deficiency for 2025 to be $296.6 million.

Q. Please describe the capital structure adjustments made in the revenue requirement calculation.

A. We made capital structure adjustments shown on MFR Schedule D-1a based on Commission precedent. First, we removed the over/under-recovery amounts for our cost recovery clauses from short-term debt and deferred taxes because these are the components of the capital structure that are affected by the difference between the clause expense incurred and the clause revenues collected. We then performed the deferred income tax specific/pro rata adjustment over all sources except for tax credits. The deferred income tax adjustment calculation is illustrated in the direct testimony and exhibit of Ms. Strickland. Finally, we used the traditional pro rata approach for the remaining adjustments, such as removing certain CWIP amounts and rate base items associated with the cost recovery clauses.

Q. Did the company make any pro forma adjustments to calculate its 2025 revenue requirement?

A. No.

Q. What revenue expansion factor and net operating income multiplier did the company use to calculate its proposed rate increase?

A. The company's proposed revenue expansion factor is 0.74424, as shown on MFR Schedule C-44, and was calculated using the regulatory assessment fee of 0.085 percent, a bad debt rate of 0.224 percent, and state and federal income tax rates of 5.5 and 21.0 percent, respectively. The tax rates are discussed in the direct testimony of Ms. Strickland.

Q. What amount of projected test year Write-offs should the Commission approve in the Revenue Expansion Factor?

A. The Commission should approve projected test year Write-offs of $5.8 million in the revenue expansion factor as shown on MFR Schedule C-11. Given expected conditions, this is a reasonable amount for write-offs for the test year.

Q. How did the company account for vehicle depreciation in its 2025 capital and O&M budgets?

A. Vehicle depreciation was included in the fleet allocation and follows the labor activities of all associated team members; therefore, it is included in both capital and O&M based on these activities.

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Q. What amount of Administrative and General ("A&G") expense was capitalized in the company's 2025 capital budgets?

A. The company capitalized $35.0 million in A&G Expenses in the 2025 Capital Budget.

Q. How did the company determine the amount of A&G expense to be capitalized in its 2025 O&M and capital budgets?

A. It is the company's practice to review A&G capitalization each year. Periodically, this accounting estimate is updated when appropriate. The update is made using an A&G Capitalization study that is performed in accordance with the Code of Federal Regulation ("CFR") and electric plant instruction 4 as practicable.

The company's review of A&G capitalization includes consideration of (a) the total level of capital expenditures occurring over time, (b) the amount of A&G expense occurring over time, (c) the level of effort devoted to capital activity in the business functions that charge A&G expense, and (d) the types of costs being charged into A&G expense accounts.

In 2022, the company performed an A&G Capitalization study

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that resulted in the implementation of an annual capitalization amount of $35.0 million. In July 2022, the company began monthly A&G capitalization postings to reflect the new annual amount. The company used this annual amount in the O&M budget for the 2025 test year.

Q. Is the amount of A&G expense capitalized in the 2025 test year reasonable?

A. Yes. The 2025 amount is reasonable in light of the overall level of 2025 capital spending and recent changes to the level of the company's capital spending, as well as the level of A&G expense projected for 2025.

Q. What Allowance for Funds Used During Construction ("AFUDC") rate did the company use for projects in 2023, 2024, and the projected 2025 test year?

A. The AFUDC rate of 6.07 percent was approved by the Commission in Order No. PSC-2022-0394-PAA-EI, Docket No. 20220162-E, effective July 1, 2022. The company used this rate for 2023, 2024, and the projected 2025 test year.

Q. Is the company's 2025 revenue requirement calculation reasonable?

A. Yes. The revenue requirement calculation described above reflects reasonable amounts of rate base and net operating income ("NOI") and a reasonable rate of return, all of which reflect appropriate amounts for adjustments approved by the Commission in prior rate cases. All forecasted amounts included in the revenue requirement calculation are reasonable and prudent amounts associated with providing electric service in 2025.

Q. Should Tampa Electric be required to file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of the Commission's findings in this rate case?

A. Yes. Tampa Electric does not object to a requirement like this.

(6) AFFILIATE TRANSACTIONS

Q. Please describe the projected affiliate transactions included in the company's 2025 test year.

A. The projected affiliate transactions included in the company's 2025 test year reflect the normal products and services exchanged with companies related to Tampa

Electric. These items include products and services provided to affiliated companies, as well as products and services provided from affiliated companies to Tampa Electric. Tampa Electric provides services to affiliates and shares the costs with them, referring to them as "shared services". Shared services are provided to many affiliates, but primarily to Peoples Gas System, Inc. and New Mexico Gas Company. Tampa Electric receives services from other affiliates, primarily Emera, Inc.

Q. Can you provide additional details regarding affiliate transactions?

A. Yes. Related party transactions are reflected on MFR Schedule C-30, Transactions with Affiliated Companies, and MFR Schedule C-31, Affiliated Company Relationships – which reflects the diversification pages that will be contained in the 2023 Form 1 submission to the Commission. In addition to the shared services discussed above, Tampa Electric engages in natural gas purchases and sales with Peoples Gas System and Emera Energy Services U.S., Inc. Tampa Electric Company also has an Asset Management Agreement ("AMA") with Emera Energy Services U.S., Inc. for a portion of its natural gas storage capacity.

Q. Does Tampa Electric adhere to Rule 25-6.1351, Florida Administrative Code ("Affiliated Transactions rule"), when conducting Affiliate Transactions and maintaining a Cost Allocation Manual ("CAM")?

A. Yes, the company believes it complies with the rule and maintains a CAM. The Affiliated Transaction rule imposes two basic requirements. First, the rule states that a utility must charge an affiliate the higher of fully allocated costs or market price for all non-tariffed services and products purchased by the affiliate from the utility. Second, it states that when a utility purchases services and products from an affiliate and applies the costs to regulated operations, the utility shall apportion to regulated operations the lesser of fully allocated costs or market price. However, these two requirements do not apply to allocation of cost for services between a utility and its parent company or between a utility and its regulated utility affiliates. In Tampa Electric's case, the vast majority of the costs allocated to Tampa Electric from affiliates or allocated to affiliates by Tampa Electric are not subject to the two requirements above.

Q. How does Tampa Electric determine the costs that it charges

C16-1676

affiliated companies?

A. The costs for Tampa Electric shared services are charged to affiliate companies pursuant to our CAM or intercompany service agreements in one of three ways: (1) direct charges, (2) assessed charges, and (3) allocated charges. Direct charges are made when an affiliate is solely receiving the product or service rendered by Tampa Electric. When multiple affiliates receive the same services, the company charges costs either through assessments or an allocation. Assessments are determined and distributed using cost-causative calculations based on certain metrics, such as head count or square footage. Shared costs that cannot be directly charged or assessed are allocated based on a Modified Massachusetts Method, which is a method that utilizes a combination of total operating revenues, total operating assets, and net income as the basis of allocation. This method has been evaluated and deemed reasonable by the Commission in prior company proceedings. This methodology is further described in the company's CAM. The allocation procedures in the CAM and used by other affiliates to allocate costs to Tampa Electric are reasonable.

Q. How do affiliated companies determine the costs that are

C16-1677

charged to Tampa Electric?

A. The costs for products or services provided to Tampa Electric from affiliated companies are charged using similar methods to the ones described above and in accordance with the Affiliate Transaction rule. The company receives direct, assessed, and allocated charges. The cost distribution is based on the nature of the service provided. Examples of these services include risk management, insurance, and treasury. There are also Emera, Inc. functions that partner with Tampa Electric and charge for their involvement. Examples of these services include safety, legal, information technology and human resources.

Q. Does Emera charge Tampa Electric for Merger or Acquisition related costs?

A. No.

Q. Please describe the changes in affiliate relationships that have occurred since the company’s last rate case.

A. Since the company’s last rate case, the only major change is the separation of Peoples Gas System from Tampa Electric. Peoples Gas System operated as a division of

Tampa Electric Company and was regulated by the Commission as a stand-alone entity. Consistent with how most utility companies are organized, Emera decided in 2022 that it was time to legally separate its Florida electric and natural gas utilities to reflect their different business needs, geographic reach, and regulatory constructs. The natural gas assets, liabilities, and equity of the Peoples Gas System, a division of Tampa Electric Company were therefore transferred as part of a tax-free exchange to a new corporation named Peoples Gas System, Inc. ("Peoples"), effective January 1, 2023 ("2023 Transaction").

Q. Has the 2023 Transaction impacted the level of cost allocations to and from Tampa Electric and its affiliates?

A. No. The 2023 Transaction did not materially impact the level of cost allocations to and from Tampa Electric and its affiliates. However, Peoples repaid Tampa Electric its intercompany debt in December 2023, so Peoples no longer pays interest expense to Tampa Electric.

Q. Does the company expect to be involved in any other restructuring activities in 2024?

A. Yes. My Original Prepared Direct Testimony discusses one other corporate restructuring. The company does not expect that change to impact the level of costs charged to Tampa Electric by affiliates or by Tampa Electric to affiliates.

Q. Are the projected affiliate transactions reflected in the 2025 test year reasonable?

A. Yes. The affiliated transactions reflected in the test year are reasonable. The services provided to affiliates and from affiliates are documented in agreements between the companies. Cost distributions for services exchanged between affiliates are based on agreed-upon methodologies. Both incoming and outgoing charges are subject to the internal control system for each company. The services provided by affiliates are appropriate and prudently incurred to achieve the most efficient and effective operation of functions that are vital to delivering utility service at a reasonable cost. The charging of costs to affiliates is reasonable and allows Tampa Electric to ensure a streamlined cost profile for functions required to prudently operate the business.

(7) 2026 and 2027 SYA

Q. How do you expect the company's financial profile and

C16-1680

condition to change after 2025?

A. The company's financial profile will evolve as projects placed in service during 2025 and 2026 begin to be reflected fully in Tampa Electric's 13-Month Average Plant in Service through 2026 and 2027. Tampa Electric expects to place several projects into service during 2025. Therefore, the first full year in service for these projects will be 2026. Additionally, the company expects to place several projects into service in 2026 and those projects will have their first full year in service in 2027.

Projects expected to go into service in 2025 include our Polk 1 Flexibility Project; Wimauma, Lake Mabel, and South Tampa Energy Storage Capacity projects; Corporate Headquarters; the Bearss Operations Center; a portion of the South Tampa Resilience project; components of the Grid Reliability and Resilience project; and Solar projects at Cottonmouth and Duette. Page 2, Document No. 5 of my exhibit provides further details on these projects, timing of in service and how they impact the 2026 SYA.

Projects expected to go into service in 2026 include our Polk Fuel Diversity Project; a portion of the South Tampa

Resilience project; components of the Grid Reliability and Resilience project; and Solar projects at Big Four and Farmland as well as solar projects at Brewster and Wimauma 3. Page 2, Document No. 5 of my exhibit provides further details on these projects, timing of in service and how they impact the 2027 SYA.

Absent additional rate relief in 2026 and 2027, these plant additions will put pressure on our ability to earn within the range of return on equity the company is proposing in this proceeding. My Original Prepared Direct Testimony discusses the impact of these projects on our expected 2026 and 2027 financial condition.

Q. What are the amounts of incremental plant in service for these assets?

A. Document No. 5, page 1, of my exhibit includes a schedule reflecting the projected 13-month average in-service value for 2026 and 2027 for these projects. The schedule also shows the expected incremental revenue requirement needed for each project.

Q. What are the in-service dates for these projects?

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A. Document No. 5, page 2, of my exhibit includes a schedule reflecting the in-service date and incremental revenue requirement for 2026 and 2027 for these projects.

Q. How would these plant additions impact company regulatory filings?

A. Given the expected rate base growth from normal plant additions and the major projects described above, and absent an alternative regulatory approach, the company anticipates that it would need to seek additional base rate relief for 2026 and 2027. Specifically, the company would expect to file another general request for base rate relief in 2025 seeking additional base revenues in 2026 and a general rate proceeding in 2026 seeking additional base revenues in 2027.

Q. Has the company considered alternatives to filing full general rate proceedings in these two years?

A. Yes. The company proposes that the Commission approve incremental SYA to cover the asset additions described above.

The first SYA would be effective for the first billing cycle in 2026 in the amount of $100,074,841 and would cover the incremental revenue requirement as described in Document No. 5 of my exhibit.

The second SYA would become effective for the first billing cycle in 2027 in the amount of $71,847,925 and would cover the incremental revenue requirement as described in Document No. 5 of my exhibit.

My Original Prepared Direct Testimony explains why the company needs subsequent year adjustments for 2026 and 2027.

Q. Please provide additional detail related to the calculation of the revenue requirements to be recovered by the company’s proposed 2026 and 2027 SYA.

A. Document No. 5 of my exhibit shows the revenue requirement for the projects to be recovered through the two SYA using the 13-month average in-service value incremental to 2025 consistent with the methodology used for the Generation Base Rate Adjustment in the 2021 Agreement.

Q. What assumptions did you make when calculating the SYA shown in Document No. 5 of your exhibit?

A. The calculations on Document No. 5 of my exhibit start with the 13-month average in-service amount, incremental to the in- service amount in the prior year revenue requirement for each SYA project. That amount is then multiplied by the 2025 Rate of Return reflected in MFR Schedule A-1 of 7.37 percent. The resulting net operating income need for each project was multiplied by the NOI Multiplier reflected in MFR Schedule A-1 of 1.34364 to gross up the amount for taxes. This resulted in the calculated return for each project.

The company based the incremental O&M projections for the SYA on amounts expected to be incurred by operations. We used the depreciation rate for 2025 for each project. We calculated incremental property tax expense for Solar projects as the prior year end net book value times an estimated percentage of the net book value of assets that is included in the property tax calculation. For Solar Wave 3 and Solar Wave 4 projects, this percentage was 20 percent (consistent with the solar property tax exemption percentage). This amount was then further multiplied by the projected millage rate of 1.63 percent. The company calculated property tax expense for non-solar projects using the prior year end original in-service amount times an estimated percentage of the original cost of assets that is included in the property tax calculation. For the Polk 1 Flexibility project, Energy Storage projects, Corporate Headquarters, Bearss Operations Center, South Tampa Resilience project, Polk Fuel Diversity project, and Grid Reliability and Resilience projects, this percentage was 55 percent (consistent with historical percentages). This amount was then further multiplied by the projected millage rate of 1.63 percent.

For the solar projects, we included a reduction for the projected production tax credits that each location is expected to generate. For the energy storage projects, we included a reduction for the projected investment tax credits that each location is expected to realize.

Finally, we added the return on assets to the operating expense total (inclusive of the benefits of production tax credits for solar projects and investment tax credits for energy storage projects) to determine the total revenue requirement for each project.

Q. What rate design principles does the company propose to use for calculating the customer rates needed to implement the 2026 and 2027 SYA?

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A. We propose that the rates to implement the SYA be calculated using the rate design methodology that will be approved by the Commission for our 2025 general base rate increase.

(8) SUMMARY

Q. Please summarize your direct testimony.

A. My direct testimony describes the reasonableness of the company's 2025 test year. I explain the budgeting process the company used to develop its financial forecasts, and why it is reasonable and reliable for operating our business and for ratemaking purposes in this proceeding. I present our proposed 2025 rate base, net operating income, and revenue requirement increase as well as the revenue requirement calculations for the company's proposed 2026 and 2027 subsequent year adjustments.

I explain how the amount of capital in other corporate investments and the level of corporate administrative & general O&M expenses are reasonable and prudent. I also summarize how the company accounts for affiliated transactions and any major changes to affiliated transactions since our last rate case.

C16-1687

These components of my direct testimony support and explain the calculations and MFR Schedules for Tampa Electric's 2025 requested rate increase of $296,611,085 and its 2026 and 2027 SYA of $100,074,841 and $71,847,925, respectively.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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(Whereupon, Volume II revised prefiled direct testimony of Jeff Chronister was inserted.)

Depreciation Study submitted on December 27, 2023, in Docket No. 20230139-EI.

Mr. Allis describes the company's proposed depreciation rates and study in detail; the Tampa Electric witness Jeff Kopp supports and explains the dismantlement study the company commissioned for inclusion in the 2023 Depreciation Study. My Original Prepared Direct Testimony also discusses depreciation expense.

Q. What depreciation period study date should be used to calculate depreciation expense for the 2025 projected test year?

A. The projected ending plant balances as of December 31, 2024, from the depreciation study that was filed on December 27, 2023, should be used.

Q. What should be the implementation date for the revised depreciate rates and amortization schedules proposed by the company in this case?

A. The Commission should approve an implementation date of January 2025 for the company's proposed, revised depreciation rates, and amortization schedules. This effective date matches our proposed effective date for our proposed new 2025 customer rates.

TAXES OTHER THAN INCOME

Q. What level of Taxes Other Than Income expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Taxes Other than Income ("TOTI") expense of $101.6 million as shown on MFR Schedule C-1. This amount is reasonable as it was forecasted using prudent estimates of property values and assessments for ad valorem tax purposes. My Original Prepared Direct Testimony discusses TOTI further.

INCOME TAXES

Q. What level of Income Tax expense should be approved for the 2025 test year?

A. The Commission should approve Jurisdictional Adjusted Income Tax expense (benefit) totaling ($8.3 million) as

C16-1690

(Whereupon, prefiled rebuttal testimony of Jeff Chronister was inserted.)

BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 20240026-EI

PETITION FOR RATE INCREASE
BY TAMPA ELECTRIC COMPANY

REBUTTAL TESTIMONY AND EXHIBIT
OF
JEFF CHRONISTER

D13-805

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
FILED: 07/02/2024

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REBUTTAL TESTIMONY AND EXHIBIT

OF

JEFF CHRONISTER

TAMPA ELECTRIC COMPANY
DOCKET NO. 20240026-EI
FILED: 07/02/2024

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY

OF

JEFF CHRONISTER

Q. Please state your name, address, occupation and employer.

A. My name is Jeff Chronister. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or the "company") as Vice President Finance.

Q. Are you the same Jeff Chronister who filed direct testimony in this proceeding?

A. Yes. I filed direct testimony on April 2, 2024, and adopted the direct testimony of Richard Latta on May 2, 2024. The notice of substitution of witness filed by Tampa Electric on May 2, 2024, is included in Document No. 1 of my Rebuttal Exhibit No. JC-3. I will refer to my direct testimony filed on April 2, 2024, as my "original" direct testimony, and my adopted testimony of Richard Latta as "Chronister Volume II."

Q. Have your title, duties and responsibilities changed

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since the company filed your prepared direct testimony on April 2, 2024, or adopted Mr. Latta's testimony on May 2, 2024?

A. No.

Q. What are the purposes of your rebuttal testimony?

A. My rebuttal testimony serves five general purposes.

First, I will address each of the net operating income ("NOI"), rate base, capital structure and rate of return ("ROR"), Clean Energy Transition Mechanism ("CETM"), and subsequent year adjustment ("SYA") adjustments, as well as the tax reform proposal recommendation, discussed in the testimony of Office of Public Counsel ("OPC") witness Lane Kollen.

Second, I will address the issues raised about affiliate transactions and allocations in the testimony of OPC witness Bion Ostrander.

Third, I will address the equity ratio proposal reflected in the testimony of Federal Executive Agencies ("FEA") witness Christopher Walters.

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Fourth, I will address three other issues raised by other intervenor and Florida Public Service Commission ("Commission" or "FPSC") staff witnesses.

Finally, in response to intervenor testimony on affordability, I will summarize some of the actions the company takes to promote the long-term cost-effectiveness and affordability of its electric service.

Q. Have you prepared an exhibit supporting your rebuttal testimony?

A. Yes. Rebuttal Exhibit No. JC-3, entitled "Rebuttal Exhibit of Jeff Chronister," was prepared by me or under my direction and supervision. The contents of this rebuttal exhibit were derived from the business records of the company and are true and correct to the best of my information and belief. My rebuttal exhibit consists of the following three documents:

Document No. 1	Notice of Substitution of Witness
Document No. 2	Dismantlement Calculations
Document No. 3	Audit Finding Responses

I. OPC WITNESS KOLLEN'S PROPOSED ADJUSTMENTS

Q. How is this area of your testimony organized?

A. Page 5 of Mr. Kollen's testimony includes a table summarizing OPC's proposed NOI, Rate Base, and Capital Structure and ROR adjustments for the company's proposed 2025 test year and OPC's proposed CETM adjustments. Page 6 of Mr. Kollen's testimony includes a table summarizing OPC's proposed adjustments to the company's proposed 2026 and 2027 SYA. I will address each of OPC's proposed adjustments as well as OPC's tax reform proposal recommendation in this portion of my rebuttal testimony. Other witnesses support the company's position on some of OPC's proposed adjustments, so I will refer to the rebuttal testimony of other witnesses where appropriate.

A. OPC's Proposed 2025 Test Year Adjustments for Net Operating Income

1. Growth Adjustment to Revenues

Q. Should the Commission approve OPC's proposed adjustment to increase test year revenues for load growth?

A. No. Mr. Kollen's proposed adjustment is based on recommendations in the testimony of OPC witness David Dismukes. Tampa Electric does not agree with Dr.

Dismukes's proposed methodology and assumptions because they ignore important facts, contain inaccuracies, are inconsistent with accepted industry best practices, and are based on outdated information. These and other reasons the Commission should reject OPC's proposed revenue adjustment are explained further in Tampa Electric witness Lori Cifuentes's rebuttal testimony.

2. Generation Maintenance Expense

Q. Should the Commission approve OPC's proposal to disallow planned generation maintenance expense for planned outages?

A. No. The company opposes this adjustment for the reasons explained in the Tampa Electric witness Carlos Aldazabal's rebuttal testimony. On page 11 of his testimony, Mr. Kollen suggests a method to "normalize" the expense in the test year without any "deferrals." His proposal does not spread the company's forecasted generation outage expenses over time. It simply disallows forecasted expenses for 2025 that exceed $12.8 million, which he states is an average amount of generation outage expenses.

Q. Does Tampa Electric agree with Mr. Kollen's proposed $12.8

million average amount?

A. Yes. The company agrees with the $12.8 million average amount of generation outage expense but disagrees that this amount should be used to calculate an expense disallowance for 2025.

Q. Did Mr. Kollen identify deferral and amortization of a portion of 2025 generation outage expenses over a benchmark as an option?

A. Yes. On page 11, Mr. Kollen notes another alternative solution "to defer the abnormally high expense in excess of the normalized expense and amortize the deferral over an extended period of time in an attempt to allocate the benefits of the abnormally high expense to the periods benefitting from the planned maintenance scope of work and expenses" (emphasis added).

Q. If the Commission decides to adjust the company's test year outage expense as Mr. Kollen's alternative approach recommended, how should Tampa Electric implement the solution?

A. If an adjustment is made to test year outage expense,

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then the incremental costs above the "adjusted" amount included in the company's test year expenses should be deferred and amortized over time.

Q. What is the amount of 2025 planned outage expense that should be deferred under the proposal and what is a reasonable amortization period?

A. Witness Kollen proposed $12.8 million as a representative amount for normal planned outage expenses. Other options for the average could include a five-year average starting with 2021 actual expenses (which is $14.1 million) or a three-year average starting with 2023 actual expenses (which is $16.0 million).

Using Mr. Kollen's $12.8 million average and the forecasted 2025 test year planned outage expense total of $25.2 million, the incremental amount to be deferred would be $12.4 million (i.e., $25.2 million minus $12.8 million).

The company proposes to amortize this $12.4 million incremental 2025 amount over three years from 2025 to 2027. This period matches the company's 2025 test year and two SYA periods.

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In this case, the annual amortization amount would be \$4.13 million (i.e. \$12.4 million divided by 3). This would result in a 2025 test year total generation outage expense of \$16.93 million (i.e. \$12.8 million "benchmark" amount plus \$4.13 million amortization amount).

Under this proposal, the 2025 system per books expense amount to be used (\$16.93 million) to calculate 2025 NOI would be \$8.27 million lower than the \$25.2 million proposed by the company in this proceeding.

3. Pension Expense Capitalization

Q. Should the Commission approve OPC's proposed adjustment to "correct" capitalization of pension costs?

A. No. The company opposes this adjustment because, as discussed in the company's response to OPC's Ninth Set of Interrogatories No. 167(a), a portion of the company's forecasted pension cost is capitalized through the fringe rate. MFR Schedule C-17 reflects pension costs in operations and maintenance ("O&M") because all benefit costs are initially posted to FERC Account 926. The fringe rate subsequently follows the allocation of labor dollars, and FERC Account 926 is credited to reflect the portion of benefits expense (including pension costs) that are capitalized. OPC's proposed reduction to expense is inappropriate because the amount of pension costs to be capitalized has already been deducted from the company's forecasted benefits expense.

4. Other Post-Employment Benefits ("OPEB") Expense Capitalization

Q. Should the Commission approve OPC's proposed adjustment to "correct" capitalization of other post-employment benefit costs?

A. No. The company opposes this adjustment because, as discussed in the company's response to OPC's Ninth Set of Interrogatories No. 167(b), a portion of the active employee OPEB cost is capitalized through the fringe rate. MFR Schedule C-17 reflects OPEB costs in O&M as all benefits costs are initially posted to FERC Account 926. The fringe rate subsequently follows the allocation of labor dollars and FERC Account 926 is credited to reflect the portion of benefits expense (including OPEB costs) that are capitalized. OPC's proposed reduction to expense is inappropriate because the amount of OPEB costs to be capitalized has already been deducted from the company's forecasted benefits expense.

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5. Long Term Incentive Plan Expense

Q. Should the Commission approve OPC's proposed adjustment to disallow long-term incentive plan ("LTIP") expense?

A. No. The company's total compensation expense for the 2025 test year is reasonable. LTIP is an important element of the company's overall compensation program that allows the company to be competitive in the labor market to attract and retain a high-quality skilled workforce. It also incents Tampa Electric's participating executives to be aware of and support the financial health of the company, which is in the long-term best interests of customers. These and other reasons the Commission should reject this proposed adjustment are explained further in the Tampa Electric witness Marian Cacciatore's rebuttal testimony.

6. Supplemental Employee Retirement Plan ("SERP") Expense

Q. Should the Commission approve OPC's proposed adjustment to disallow SERP expense?

A. No. The company's total compensation expense for the 2025 test year is reasonable. The SERP is one component of an overall compensation and benefits package designed to retain talented, highly motivated and effective executive leadership. These and other reasons the Commission should reject this proposed adjustment are explained further in the rebuttal testimony of Ms. Cacciatore.

7. Affiliate Transaction Expense

Q. Should the Commission approve OPC's proposed expense adjustments for affiliate transactions and allocations?

A. No. The company opposes the affiliate transaction adjustments totaling $6.313 million shown on page 5 of Mr. Kollen's testimony for the reasons explained later in Section II of my rebuttal testimony.

8. Directors and Officers ("D&O") Insurance Expense

Q. Should the Commission approve OPC's proposed adjustment to disallow 50 percent of D&O insurance expense?

A. No. The Commission should reject OPC's proposed adjustment for two reasons. First, D&O insurance has long been recognized by the Commission as an expense for coverage that allows the company to attract and retain talent in director and officer positions. Second, the amount is reasonable. The cost associated with D&O insurance expense is reflected in the Administrative & General ("A&G") functional expense group. A&G expense for

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the 2025 test year is $56.0 million below the Commission's benchmark.

9. Board of Directors Expenses

Q. Please comment on OPC's proposed $(376,000) adjustment to remove 50 percent of Board of Directors expenses.

A. This is a reasonable expense, and the Commission should reject OPC's proposed adjustment.

10. Feeder Hardening Depreciation Expense

Q. Should the Commission approve OPC's proposed adjustment to disallow depreciation expense associated with feeder hardening?

A. No. The proposed feeder hardening depreciation adjustment is related to the recommendation on page 19 of the testimony of OPC witness Kevin Mara "that all feeder hardening costs be shifted to the SPP." This recommendation would be contrary to the accounting methods agreed to by OPC and approved by the Commission in Order No. PSC-2020-0224-AS-EI, filed June 30, 2020.

The costs that Mr. Mara described as being "assigned to rate base" are costs of removal ("COR"). The Commission-

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approved agreement noted above states, in Section III, "For assets being retired and replaced with new assets as part of an SPP program, TECO will not seek to recover the cost of removal net of salvage associated with the related assets to be retired through the SPPCRC. Rather, such cost of removal will be debited to TECO's accumulated depreciation reserve according to normal regulatory plant accounting procedures."

This approach recognizes that the depreciation expense for the removed assets incorporated the recovery of COR through base rates in prior years. Properly charging them to the reserve allows for the continued analysis of net book value, COR, depreciation expense and accumulated reserves in the normal context of periodic depreciation studies. If the company booked COR to the SPP, then it would inappropriately allow the company to recover a return on investment on those costs through the SPP Cost Recovery Clause.

11. Energy Storage Depreciation Expense

Q. Should the Commission approve OPC's proposal to reduce depreciation expense to reflect a 20-year life for energy storage devices?

A. No. The Commission should not approve OPC's proposed 20-year life for energy storage devices for the reasons explained in the rebuttal testimony of Ned Allis. The company's proposed life of 10 years is reasonable, especially as utility scale energy storage assets are relatively new in the industry. However, if the Commission approves a 20-year life for energy storage devices, then the 2025 adjustment, after applying the jurisdictional factor and the revenue gross-up multiplier (which excludes the federal and state income tax) would be $(5.942) million.

12. Solar Facility Depreciation Expense

Q. Should the Commission approve OPC's proposal to reduce depreciation expense to reflect a 35-year life for solar generating facilities?

A. No. As explained in the rebuttal testimony of Mr. Allis, the Commission should reject OPC's proposal. However, if the Commission approves a 35-year life for solar assets, the 2025 adjustment, after applying the jurisdictional factor and the revenue gross-up multiplier (which excludes the federal and state income tax) should be $(9.519) million.

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13. Dismantlement Expense

Q. Do you agree with Mr. Kollen's characterization, on page 27, of the company's calculation of dismantlement expense in this proceeding?

A. No. Mr. Kollen's testimony reflects an understanding of some of the elements of the dismantlement study. However, some of his testimony does not reflect an understanding of how the complete process worked, including the calculation of the dismantlement expense accrual.

Q. Please summarize how the company prepared the depreciation and dismantlement studies and the dismantlement expense accrual for this case.

A. There were three separate workstreams.

First, at the direction of the company, Mr. Allis, a member of the consulting firm Gannett Fleming, performed the Depreciation Study filed in December 2023 as discussed in his testimony. A company employee prepared the depreciation study in the company's last rate case.

Second, witness Jeff Kopp, a member of the consulting firm 1898 & Co., prepared a Decommissioning Cost Study reflecting estimates of the current cost of dismantling the company's assets. His Decommissioning Cost Study was filed with the Commission in December 2023 as discussed in his testimony. Mr. Kopp prepared the decommissioning cost estimate in the company's 2021 rate case.

Third, the company used Mr. Kopp's dismantlement cost estimates to calculate the dismantlement expense accrual in accordance with Rule 25-6.04364, F.A.C. The resulting dismantlement expense is reflected in the minimum filing requirement schedules submitted in this docket by the company on April 2, 2024. It was also used to calculate the company's 2025 proposed NOI. The company prepared the proposed dismantlement accrual in its last rate case and in this case.

Q. When did the company file the depreciation and dismantlement studies used to calculate its 2025 test year NOI in this case?

A. The company filed a petition for approval of its depreciation and dismantlement studies in December 2023. That filing, which was assigned Docket No. 20230139-EI, included (1) Mr. Allis's depreciation study, (2) Mr. Kopp's dismantlement cost estimates, and (3) the company's dismantlement expense accrual model. Docket No. 20230139-EI was consolidated with this rate case docket on April 16, 2024.

The company's December 2023 filing in Docket No. 20230139-EI included the following exhibits:

Exhibit 1	Company Background and Change in Depreciation and Dismantlement Expense Accruals Summary
Exhibit 2	Depreciation Study, including survivor curves, service life consideration, net salvage consideration, and depreciation rate calculations
Exhibit 3	Annual dismantlement accrual calculation
Exhibit 4	Depreciation Annual Status Reports (2021-2024)

A copy of the dismantlement expense accrual detailed model calculations included as Exhibit 3 to the company's December 2023 filing is included in Document No. 2 of my rebuttal exhibit.

Q. Did the company include the details of the dismantlement expense accrual model in its initial filing in this case?

A. No. The company did not and has not in previous rate case filings; however, it was part of the company's December 2023 filing. Tampa Electric produced the accrual model details to the parties in this case in response to Florida Industrial Power Users Group's ("FIPUG") Second Request for Production of Documents No. 25 and Staff's Third Request for Production of Documents No. 19.

Q. Please summarize how the dismantlement expense accrual for 2025 was developed in this case.

A. Mr. Kopp developed engineering estimates of the current costs to dismantle the company's assets. His estimate did not include cost contingencies or cost escalations. The company took Mr. Kopp's current dismantlement cost estimates, added a 15 percent contingency, and escalated the resulting amounts based on the projected retirement date of each unit to yield an estimate of the future costs of dismantling per unit. The company then compared the future expected costs of dismantlement per unit to its existing dismantlement reserve and calculated the annual dismantlement expense accruals needed to achieve the future target reserve amounts over the remaining life of the units. The company then calculated an average of the next four years of expense accruals to create a levelized annual amount for ratemaking purposes. The sum of these levelized expense accrual amounts were then used as the dismantlement expense included in the calculation of 2025 test year NOI.

Q. What is included in Document No. 2 of your Rebuttal Exhibit?

A. It is Exhibit 3 of our December 2023 filing and includes our 2025 Annual Accrual Summary (page 535), Change in Accrual Summary (page 536), 1898 & Co. cost estimate linkage to accrual model (page 537), Vendor Cost Estimates No Contingency Applied (page 538), 15 percent Contingency Amount Calculation (page 539), Cost Estimates with 15 percent Contingency Applied (page 540), Unit Reserves as of December 31, 2024 (pages 541 to 551), Inflation Forecast (pages 552 to 553), and Unit Accrual Calculations (Pages 555 to 648).

Q. Did the company develop its dismantlement study and 2025 expense accrual in accordance with the Commission's rule?

A. Yes. The dismantlement expense accrual model and calculations follow the requirements in Rule 25-6.04364, F.A.C. This rule calls for the use of escalation factors

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[25-6.04364(3)(f) and (m) and 25-6.04364(4), F.A.C.], requires consideration of all dismantlement related expenditures including environmental remediation costs [25-6.04364(2)(c), F.A.C.], and contemplates the consideration of contingencies [25-6.04364(2)(a), F.A.C].

Q. Is the company's dismantlement study expense accrual reasonable?

A. Yes. The company's proposed amount of dismantlement expense for the 2025 test year is based on the reasonable dismantlement estimates prepared by Mr. Kopp and the accrual calculated in accordance with the applicable F.A.C. rule and is reasonable.

14. Dismantlement Expense for Escalations

Q. Should the Commission include projected cost increases beyond 2025 when calculating dismantlement expenses?

A. Yes. The purpose of a dismantlement study is to estimate the future costs of retiring plant assets, so reasonable estimates of future cost increases should be considered. The company disagrees with OPC's position on this issue for the reasons explained in the rebuttal testimony of Mr. Kopp, and because, as discussed above, the applicable rule requires consideration of escalation factors and future costs.

15. Dismantlement Expense for Solar Site Restoration

Q. Should the Commission approve OPC’s proposed adjustment to disallow solar site restoration environmental costs from dismantlement expense?

A. No. These are reasonable and prudent costs that should be included and accounted for at the solar generating asset facilities just as they are at other company generating facilities. It is not reasonable to disallow environmental restoration costs that the company reasonably expects to incur at the time of dismantlement. These and other reasons the Commission should reject this proposed adjustment are explained further in the rebuttal testimony of Mr. Kopp.

16. Dismantlement Expense Related to Solar Generation Life

Q. Should the Commission approve OPC’s proposed adjustment to reduce dismantlement expense to reflect a 35-year life for solar generating assets?

A. No. The company disagrees with OPC’s position on this issue for the reasons explained in the rebuttal testimony of Mr. Allis. However, if the Commission approves a 35-year life for solar assets, the 2025 NOI adjustment for dismantlement expense, after applying the jurisdictional factor and the revenue gross-up multiplier (which excludes the federal and state income tax) should be $(1.293) million. This expense reduction amount is calculated in isolation and does not embed the adjustments for removing escalation and removing environmental remediation costs. However, if the Commission adopts those changes, the corresponding proposed changes to accumulated depreciation should be approved.

17. Carrying Costs on Deferred Production Tax Credits

Q. Should the Commission approve OPC's proposal to include carrying costs on deferred production tax credits ("PTC") through December 31, 2024, in test year NOI?

A. No. Deferred PTC were recorded as regulatory liabilities from 2022 to 2024. Over this period, they were properly reflected as rate base reductions in the company's Earnings Surveillance Reports. In the 2025 test year, the unamortized balance of the regulatory liabilities related to deferred PTC are reductions to rate base. As a result, the revenue requirement requested in this proceeding is lower already. There is no need for the adjustment proposed by OPC.

18. Deferred PTC Amortization Period

Q. Should the Commission approve OPC's proposal to amortize the regulatory liability associated with deferred PTC over three years instead of the 10 years proposed by the company?

A. No. The Commission should not approve OPC's proposed 3-year amortization for the deferred PTC benefit regulatory liability. These benefits were put on the balance sheet for the express purpose of flowing them to customers as new rates were set in our next rate proceeding.

The company's proposed amortization period of 10 years is reasonable because it shares the benefit of deferral with customers over a longer period. Using a three-year amortization period would be beneficial to customers for three years but would create an abnormal expense reduction and enhance the potential need for rate relief at the end of the amortization period. Mr. Kollen's revenue requirement adjustment also included impacts of a carrying charge discussed above which should be rejected for the reasons explained above.

If the Commission prefers a middle ground, a five-year amortization period would spread the benefit of the deferral over a longer period than proposed by OPC and would moderate the impact of the atypical expense reduction described above. If the Commission approves a five-year amortization for the regulatory liability, the 2025 NOI adjustment, after applying the jurisdictional factor and the revenue gross-up multiplier (which excludes the federal and state income tax) would be $(5.520) million.

19. Deferred IRA Investment Tax Credits Amortization Period

Q. Should the Commission approve OPC's proposal to amortize deferred investment tax credits ("ITC") associated with energy storage devices over three years?

A. No. The company opposes OPC's proposed adjustment because it does not reflect a normalization method of accounting. By spreading the benefit of ITC over an asset's regulatory life, normalization avoids intergenerational cost inequities for customers and allows the customers who will be getting the benefit of the asset to also enjoy the benefit of the related ITC. As described in Tampa Electric witness Valerie Strickland's rebuttal testimony, the company's proposed methodology complies with IRS normalization rules and is consistent with the company's historical treatment of its Deferred ITC. The company's treatment is consistent with the FPSC's historic practice for ITC, which has been reflected in Commission orders for the last several decades.

20. Deferred Solar ITC Amortization Period

Q. Should the Commission approve OPC's proposal to amortize pre-2022 solar ITC over 35 years rather than 30 years?

A. No. As explained in the rebuttal testimony of Mrs. Strickland, the amortization of the deferred solar ITC should match the regulatory life of 30 years, as proposed in the company's recently filed Depreciation Study.

B. OPC's Proposed 2025 Test Year Adjustments for Rate Base

1. Spare Power Transformers

Q. Should the Commission approve OPC's proposed rate base adjustment to remove spare power transformers?

A. No. The current lead time to obtain a transformer is approximately two to three years, so ordering spares annually is needed to serve customers in the event of transformer failure. If the company is unable to maintain a healthy spare inventory, the company may be required to purchase emergency replacements at higher costs. The proposed disallowance would create reliability risk and could increase customer costs. These and other reasons the Commission should reject this proposed adjustment are explained in the Tampa Electric witness rebuttal Chip Whitworth's rebuttal testimony.

2. Distribution Feeder Hardening Plant

Q. Should the Commission approve OPC's proposed rate base adjustment to remove distribution feeder hardening plant?

A. No. The proposed feeder hardening rate base adjustment is related to the recommendation on page 19 of the testimony of Mr. Mara "that all feeder hardening costs be shifted to the SPP." This recommendation should be rejected for the reasons explained in Section I.A.10., above.

3. OPC Proposed Adjustments to Accumulated Depreciation

Q. Should the Commission approve OPC's proposed adjustment to accumulated depreciation to reflect different depreciation lives for solar generating facilities and energy storage devices?

A. No. OPC's proposed changes to the depreciation service lives for solar generating facilities and energy storage devices should be rejected for the reasons previously explained in this testimony. However, if the Commission adopts those changes, the corresponding proposed changes to accumulated depreciation should be approved.

4. Rate Base Adjustments for PTC

Q. Should the Commission approve OPC's two proposed rate base adjustments relating to the company's regulatory liability for deferred PTC?

A. No. The company opposes those adjustments for the reasons explained above and in the rebuttal testimony of Mrs. Strickland, namely the company's disagreement with certain data points used to calculate the rate base adjustment. However, if the Commission approves OPC's positions on PTC carrying costs and amortization, it should also approve any corresponding rate base adjustments.

C. OPC's Proposed 2025 Test Year Adjustments for Capital Structure and ROR

1. Cost Rate for Deferred Energy Storage ITC in Capital Structure

Q. Should the Commission approve OPC's proposed revenue requirement adjustment to assign a zero cost to the balance of energy storage deferred ITC in the capital structure?

A. No. The company's methodology complies with IRS normalization rules and is consistent with the company's historical treatment of its Deferred ITC. The company's treatment is consistent with FPSC practice, which is to assign a cost of capital for the Deferred ITC using the weighted average cost rate of investor sources of capital. This practice has been codified in Commission orders for the last several decades. These reasons for rejecting this proposed adjustment are explained further in the rebuttal testimony of Mrs. Strickland.

2. Return on Equity

Q. Should the Commission approve OPC's proposed revenue requirement adjustment to reflect a 9.5 percent mid-point return on equity ("ROE")?

A. No. The Commission should reject OPC's proposed ROE adjustment. Mr. Kollen's proposed adjustment is based on the recommended ROE in the testimony of OPC Witness Randall Woolridge. Tampa Electric does not agree with Dr. Woolridge's observations surrounding current capital market conditions, his review of authorized ROE, his

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application of the DCF model, nor his application of the CAPM. These points are explained further in the rebuttal testimony of Dylan D'Ascendis.

D. OPC's Proposed CETM Adjustments

Q. What is the CETM?

A. CETM stands for Clean Energy Transition Mechanism. It was approved by the Commission in 2021 when the Commission approved the company's 2021 Settlement Agreement. Tampa Electric witness Ashley Sizemore explains the CETM and presents the company's proposed updated CETM factors for 2025 and thereafter in her direct testimony.

1. Cost Rate for Deferred Energy Storage ITC in capital structure

Q. Should the Commission approve OPC's proposed CETM adjustment to assign a zero cost to the balance of energy storage deferred ITC in the capital structure?

A. No. The Commission should reject OPC's proposed energy storage ITC adjustment for the reasons described in Section I.C.1., above and in the rebuttal testimony of Mrs. Strickland.

2. Return on Equity

Q. Should the Commission approve OPC's proposed CETM adjustment to reflect a 9.5 percent mid-point ROE?

A. No. The Commission should reject OPC's proposed ROE adjustment for the reasons explained in Section I.C.2., above.

E. OPC's Proposed 2026 and 2027 SYA Adjustments

1. Remove Grid Reliability and Resilience ("GRR")

Q. Should the Commission approve OPC's proposed adjustment to remove the GRR Projects from the company's proposed 2026 and 2027 SYA?

A. No. The GRR Projects build on Tampa Electric's existing grid modernization strategy and will provide new and enhanced functionality across the investments. The projects will provide customers with greater access to data which is critical to meet customer expectations and enable more efficient and effective operations within Tampa Electric. The prudence of the GRR Projects included in the company's proposed 2026 and 2027 SYA are explained further in the Tampa Electric witness David Lukcic's rebuttal testimony.

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Q. Should the fact that the GRR Projects are not generating assets disqualify them for recovery through a SYA?

A. No. Although the Commission has approved SYA for cost recovery of generating assets in the past, there are no practical or ratemaking reasons why a SYA should not include major grid improvement projects. The purpose of a SYA is to allow cost recovery for future major projects without filing multiple future test years or filing a rate case every year. The company's GRR program is a major project and including components of it for recovery through an SYA will mitigate the need for the company to file "full" rate cases in 2026 and 2027.

2. Remove Income Tax Gross Up on Non-equity Return

Q. Should the Commission approve OPC's proposal to remove the income tax gross up in non-equity return capital structure components?

A. Yes. The logic of OPC's adjustment is correct. The company's position is that the GRR Projects should be included in the 2026 and 2027 SYA; therefore, the amount of the adjustment to remove the income tax gross up should be $(4,739,104) for 2026 and $(3,262,486) for 2027.

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3. Imputed Revenue Adjustment

Q. Should the Commission adopt OPC's proposal to reduce the company's 2026 and 2027 SYA by imputing incremental revenues for those periods?

A. No. The Commission should reject OPC's proposed SYA adjustments because of two flaws in OPC's position.

The first flaw is its reliance on methods and assumptions objected to in the rebuttal testimony of Mrs. Cifuentes. Mr. Kollen's proposed SYA adjustments are based on 2026 and 2027 revenue projections in the testimony of OPC witness Dr. Dismukes. Tampa Electric does not agree with Dr. Dismukes's proposed methodology and assumptions as they overlook important facts, contain inaccuracies, are inconsistent with accepted industry best practices, and are based on outdated information.

The second flaw is the application of all of Dr. Dismukes's projected 2026 and 2027 revenue growth amounts to only the assets in the company's proposed SYA. Even if the company agreed with Dr. Dismukes' annual growth increments of roughly $8 million and $6 million, those figures would be revenue available to recover the total rate base growth for Tampa Electric in those future years.

The Commission has for decades acknowledged that future year revenue growth allows utilities to reasonably invest in additional rate base without having to come in every year for rates. The specific assets included in the SYA are just a subset of the total assets that the company will invest in to serve customers in the years after 2025.

Imputing incremental 2026 and 2027 revenue into the calculation of the company's proposed 2026 and 2027 SYA would simply serve to moderate the benefits to all parties from SYA and increase the likelihood that the company would need additional rate relief in those years.

4. Remove Incremental O&M Expenses

Q. Should the Commission adopt OPC's proposal to disallow O&M expenses associated with the projects included in the company's proposed 2026 and 2027 SYA?

A. No. The Commission should reject this proposed adjustment because these O&M expenses, which will be incurred in 2026 and 2027, are incremental to the O&M expense amounts included in the company's 2025 test year and are related to the specific SYA projects. The company's proposal to recover incremental O&M is consistent with the method used to calculate revenue requirements for prior base rate adjustments. Both OPC's revenue and expense adjustments to the SYA should be rejected.

5. Other Revenue Requirement Adjustments

Q. Consistent with its positions on the company's 2025 test year, OPC proposes to adjust the company's 2026 and 2027 SYA amounts to reflect (a) longer depreciation lives for solar and energy storage devices, and (b) a three-year amortization period for deferred ITC associate with energy storage devices. Should the Commission approve these adjustments?

A. No. The Commission should decline to make these adjustments to the company's proposed 2026 and 2027 SYA for the same reasons – described above – that it should not make these adjustments to the company's 2025 test year revenue requirement. However, if the Commission adopts OPC's position on any of these issues for the company's 2025 test year revenue requirement, it should make the same adjustment to the company's proposed 2026 and 2027 SYA.

6. Cost Rate for Deferred Energy Storage ITC in capital structure

Q. Should the Commission approve OPC's proposed SYA adjustment to assign a zero cost to the balance of energy storage deferred ITC in the capital structure?

A. No. The Commission should reject OPC's proposed energy storage ITC adjustment for the reasons described in Section I.C.1., above and in the rebuttal testimony of Mrs. Strickland.

7. Return on Equity

Q. Should the Commission approve OPC's proposed SYA revenue requirement adjustment to reflect a 9.5 percent mid-point ROE?

A. No. The Commission should reject OPC's proposed ROE adjustment for the reasons explained in Section I.C.2., above.

F. Tax Reform Proposal

Q. Should the Commission approve the Company's proposed tax reform provision or reject the proposal as advocated by OPC?

A. The company continues to believe that its proposed tax reform mechanism would be a useful regulatory tool and should be approved. It is designed to address tax rate increases and decreases, and a similar mechanism was the basis for (a) the identification of a $102.7 million revenue requirement impact that was netted against storm costs for 2018 and reduced base rates effective January 1, 2019 and (b) a credit of approximately $5 million to the ECCR for 2019 and a related base rate reduction effective January 1, 2020 for a state tax rate decrease.

II. AFFILIATE TRANSACTIONS AND ALLOCATIONS

Q. What is your general assessment of Bion Ostrander's testimony in this case?

A. Mr. Ostrander's testimony identifies several "concerns", proposes specific adjustments, and invites the Commission to adopt nine recommendations for Tampa Electric as a "centralized service provider." The Commission should not adopt any of his proposed adjustments or suggestions for the reasons specified in this portion of my rebuttal testimony.

A. General Concerns

Q. As a preliminary matter, do you agree with Mr. Ostrander's concern about the timeliness and quality of the company's responses to his requests for information?

A. No. OPC sent discovery on affiliate transactions to Tampa Electric before the company filed its petition and direct testimony. OPC's initial discovery on affiliate transactions appeared to be boiler plate questions used by Mr. Ostrander in other states and were not tailored to Tampa Electric's circumstances or based on an analysis of the company's initial filing. The quality of the company's responses is reflected in the content of explanations provided and the layers of detailed cost breakdowns submitted. The timeliness and quality of the company's responses were consistent despite the significant volume of formal discovery requests and informal requests.

On the subject of affiliate transactions alone, the company responded to over 100 interrogatories and requests for production of documents from OPC, with a total of over 275 questions including subparts. The company provided additional information on affiliate transactions during my deposition and in the deposition late filed exhibits. In addition to these formal responses, the company also provided information informally in three ways: (1) two informal meetings with Mr. Ostrander where company representatives provided explanations on process, accounting, and reporting for affiliate transactions, (2) early delivery of discovery responses (the company sent over 50 emails directly to OPC with files and explanations ahead of discovery due dates), and (3) delivery of responses to three pages of additional clarifying questions (CQ-1 through CQ-3).

Q. On pages 21 through 24 of his testimony, Mr. Ostrander discusses Florida's cost allocation and affiliate transaction rules. Do you agree with the positions presented by Mr. Ostrander in this section of his testimony?

A. No. On line 19 of page 24, Mr. Ostrander concludes that "existing Florida affiliate transaction rules provide very minimal protective measures to consumers." I strongly disagree with that characterization.

Mr. Ostrander quotes four different relevant sections of the Commission's rules, including Rule 25-6.1351(3)(a), F.A.C. which states "All affiliate transactions, however, are subject to regulatory review and approval." Despite this rule statement, Mr. Ostrander suggests that most of Tampa Electric's affiliate transactions lack meaningful review.

Q. On line 21 of page 24, Mr. Ostrander recommends that "the

Commission explore adding more protective measures" for affiliate transactions. Do you agree?

A. No. I believe the recommendation, as well as most of Mr. Ostrander's positions, reflects a lack of careful study of Florida's affiliate transaction rules and monitoring methods and Tampa Electric's compliance with those rules and methods. Indeed, his recommendations really appear to be criticisms of the Commission's approach to regulating affiliate transactions.

Each year, Tampa Electric files information requested by the FPSC as an addition to FERC Form No. 1, called the Diversification Pages. These annual pages (officially numbered 451 to 460) involve about 30 pages of data and reflect a significant amount of information available to the Commission and consumer parties. The Commission reviews this information and can send data requests if warranted.

Many of Mr. Ostrander's concerns that the company failed to provide supporting documentation - and most of his questions that he calls unresolved matters - reflect his lack of understanding of the information provided to OPC and the information provided annually by Tampa Electric to the FPSC.

For example, Mr. Ostrander's questions frequently ignored the designation of incoming and outgoing affiliate charges as presented as "P" and "S" on Page 457 of the Diversification Pages. Also, Mr. Ostrander's claim that there was a lack of explanation and clarity for affiliate agreements ignores the information for every affiliate agreement presented on Page 455 of the Diversification Pages.

Q. Are the positions in Mr. Ostrander's testimony reasonable given the content of his section VI. and given your comments above?

A. No. When Mr. Ostrander states that Florida affiliate transaction rules do not provide adequate protective measures for consumers, he ignores the Commission's authority to review all these transactions and fails to acknowledge Tampa Electric's adherence to these rules. His suggested adjustments are not grounded in fact or reasonable logic.

Q. Mr. Ostrander expresses concerns about Emera's use of the Nova Scotia Power cost allocation manual ("CAM"). Do you agree with this concern?

A. No. Nova Scotia Power, Inc. ("NSPI") existed before the establishment of the Emera parent company. When transactions began to occur between NSPI and Emera, they immediately came under the jurisdiction of the Nova Scotia Utility and Review Board ("UARB"). As NSPI's regulator, the UARB reviews and approves the NSPI CAM and monitors compliance with it. The NSPI CAM covers transactions between Emera and NSPI. There is no need to create a redundant document that isolates Emera charges when they are covered by the existing NSPI CAM.

Q. Should the Commission be concerned about the levels of costs allocated and attributed to and from Tampa Electric and its affiliates?

A. No. The Commission monitors affiliate transactions through the Diversification Pages and in FPSC audits, allowing it to validate reasonable and prudent cost levels at Tampa Electric and other regulated utilities. The Commission's oversight of shared services and their related cost levels has proven to be effective. In addition to oversight in Florida, the UARB conducts its scrutiny of affiliate transactions among Emera companies.

This indirect review by another regulator should provide additional confidence that the costs allocated to and from Emera to other affiliates are reasonable.

Finally, the appropriateness of cost distributions to and from Tampa Electric and its affiliates is reflected in Tampa Electric's performance against the Commission's benchmark. With the vast majority of parent and affiliate charges being recorded in the A&G functional expense group, the prudence of cost levels is reflected in Tampa Electric's 2025 test year A&G expense, which is $56.0 million below the Commission's benchmark.

B. Proposed Adjustments

Q. Should the Commission reduce the company's test year O&M expenses by $858,561 as proposed by Mr. Ostrander?

A. No. The adjustment, named BCO-1, is not appropriate for the following reasons:

First, the adjustment subtracts an amount that is not in the company's 2025 test year budget. Although Mr. Ostrander states on page 55 of his testimony that "this amount is an Emera allocated expense that will impact TECO's expenses", and that "TECO has not provided any supporting documentation," he then correctly depicts in his chart on page 53 that this $858,561 is not in the company's 2025 budget.

Second, the adjustment is based on incorrect information. Mr. Ostrander indicates, at the bottom of page 54, that Emera's direct and allocated charges to TECO "do not impact TECO expenses because these charges are treated as an Accounts Receivable accounting entry." As reported on Tampa Electric's 2023 Diversification Page 457C, these charges are recorded in account 930 and other multiple FERC expense accounts. They are not recorded in Accounts Receivable (account 146).

Third, Mr. Ostrander supports his proposed adjustment with incorrect information and incorrect logic. Mr. Ostrander relates, at the top of page 56, the $858,561 to the "transfer (of) expenses of dissolved TECO Services, Inc. to TECO operations in 2024." He then states that "TECO has not explained why it is reasonable to transfer its expenses to TECO."

The $858,561 cost charged from Emera to Tampa Electric in 2023 is not related to the dissolution of TECO Services, Inc. Tampa Electric provided interrogatory responses and person-to-person explanation to OPC and Mr. Ostrander that Tampa Electric was previously charged some shared services with that description in the years prior to 2024 but did not budget these charges in that manner in 2024 or 2025.

Fourth, the adjustment ignores the fact that the Emera charges budgeted to expense in the 2025 test year are lower than the Emera charges incurred in 2023 and prior years. As reflected in Mr. Ostrander’s chart on page 53, the budgeted amount in the 2025 test year for Emera charges is less than the actual amounts for 2023. Also, as reflected in the company’s response to OPC’s Fifth Set of Interrogatories No. 98, the budgeted amount in the 2025 test year for Emera charges is $13,859,000, which is less than the actual amounts for 2023, $14,856,777, and 2022, $15,394,031.

Q. Should the Commission reduce the company’s test year O&M expenses by $5,457,472 as proposed by Mr. Ostrander?

A. No. The adjustment, named BCO-2, is a combination of four proposed adjustments, as presented on page 60 of Mr. Ostrander’s testimony. I will address each proposed adjustment below.

Q. Should the Commission reduce the company's test year O&M expenses by $400,000 based on Mr. Ostrander's changes to the calculation of allocation factors?

A. No. The adjustment, named BCO-2.1, is not appropriate because Mr. Ostrander has, per page 62, "removed the Net Income factor and replaced it with a 2023 Headcount factor and updated some of the remaining Revenues and Net Asset factors." This deviation from the calculation methods approved by the FPSC for the last several rate cases causes inconsistency, without proof that this methodology change will be prudent for cost distribution during the period when new rates will be in effect.

Q. Should the Commission reduce the company's test year O&M expenses by $3.6 million based on Mr. Ostrander's proposal to disallow one half of corporate responsibility expenses?

A. No. The adjustment, named BCO-2.2, is not appropriate because Mr. Ostrander has proposed to disallow costs because of his opinion that, per page 62, "TECO has not provided any documentation to prove these corporate expenses are not duplicative of other corporate-type expenses or that they are not excessive." Mr. Ostrander's opinion ignores the significant documentation provided by the company (discussed earlier in my rebuttal testimony), the Commission's long-standing oversight of affiliate transactions and corporate responsibility expenses, and the fact that corporate responsibility expenses are recorded in the A&G functional expense group which, for the 2025 test year, is $56.0 million below the Commission's benchmark.

Q. Should the Commission reduce the company's test year O&M expenses by $200,000 based on Mr. Ostrander's changes to the calculation of headcount allocation factors?

A. No. The adjustment, named BCO-2.3, is not appropriate because Mr. Ostrander describes this adjustment, on page 72, as "more of a routine adjustment that does not need much explanation." This adjustment inappropriately uses historical data rather than the 2025 test year data, which test year data is more indicative of employee count during the time period when new rates will be in effect.

Q. Should the Commission reduce the company's test year O&M expenses by $1.3 million based on Mr. Ostrander's changes to the calculation of procurement cost allocation factors?

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A. No. The adjustment, named BCO-2.4, is not appropriate because Mr. Ostrander has proposed to disallow costs because of his opinion that, per page 73, "TECO has become saddled with almost all residual Procurement expenses because TECO has failed to responsibly control, or justify, these increasing levels of centralized service expenses." Mr. Ostrander's opinion ignores the significant documentation supporting transactions provided by the company, the Commission's long-standing oversight of these expenses, and the fact that procurement expenses are recorded in the A&G functional expense group which is $56.0 million below the Commission's benchmark.

Equally important is that Mr. Ostrander's opinion ignores the fact that the costs involved are not residual or remaining costs. Rather the costs incurred by Tampa Electric are for the activities that specifically serve Tampa Electric's procurement needs. This is reflected in the amounts on the company's books for 2020 through 2023. In that time, Tampa Electric procurement expense grew from $3.3 million to $4.8 million. This $1.5 million increase was 46 percent. During the same period, the dollars for purchase orders processed for Tampa Electric increased 37 percent, and the dollars for vendor invoice payments for Tampa Electric increased 47 percent. The amount of procurement costs included in the 2025 test year O&M expense is reasonable and prudent.

C. Centralized Service Provider Recommendations

Q. Should the Commission be concerned about the role Tampa Electric plays as a centralized service provider?

A. No. Over time, customers have benefited from Tampa Electric's cost discipline and efficient business processes. The benefit of having shared service functions is that it mitigates duplicative costs that would be incurred by each regulated affiliate if they each had individual functions at each company. The Commission has monitored affiliate transactions through the Diversification Pages and in FPSC audits, allowing it to validate reasonable and prudent cost levels at each company. The Commission also, during each rate case proceeding, has examined the functional distribution of responsibilities among affiliates, focusing on where individual company attention is needed and where a shared service approach is cost effective. The Commission ensures that functional structure and cost levels are reasonable and prudent.

Q. Should the Commission adopt Mr. Ostrander's nine recommendations for Tampa Electric as a centralized service provider?

A. No. Mr. Ostrander's nine suggestions for Tampa Electric as a centralized service provider should be rejected for several reasons.

First, if they are to be considered at all, they should only be considered in a rulemaking or other proceeding applicable to other public utilities operating under the jurisdiction of the Commission. Rule 25-6.1351, F.A.C. on Cost Allocations and Affiliate Transactions has served the Commission well for many years, and requirements like the ones proposed by Mr. Ostrander should only go into effect through amendments to this rule.

Second, Mr. Ostrander's recommendations ignore important facts. Emera charges in the 2025 test year of $13.9 million represent less than four percent of Tampa Electric's total O&M expense. In addition, the shared service costs which are contained in the company's O&M are subject to consistent review by the Commission through its robust monitoring procedures. The costs questioned by Mr. Ostrander are primarily recorded in the A&G functional expense group which, for the 2025 test year, is $56.0

million below the Commission's benchmark.

Finally, the nine recommendations are either overly burdensome or redundant. The suggestions in items one, two, three, four, and six would create unnecessary administrative burden and require incremental costs to be borne by customers. The suggestions in items five, seven, eight, and nine are procedures that are already in place. The company's internal controls, accounting, invoicing, tracking, management monitoring and analysis, Diversification reporting, and internal, external & regulatory audits collectively provide the Commission assurance that affiliate transactions are reasonable and prudent.

III. EQUITY RATIO

Q. Should the Commission approve the 52 percent equity ratio (investor sources) recommended by FEA witness Christopher Walters?

A. No. Credit rating agencies consider the regulatory environment of an electric utility to be a key consideration in determining the creditworthiness of an energy utility. Regulators determine an appropriate capital structure and establish the allowed return on equity, and these are two of the key variables that go into determining a utility's revenue requirement, and by extension, the debt level and cash flow generating capability of the company.

Reducing the company’s requested equity ratio would result in a reduction to the revenue requirement and would have a negative effect on credit metrics and financial integrity. Tampa Electric’s obligation to serve its customers and the significant capital expenditure requirements needed to maintain, modernize and grow its system is better served by stronger financial integrity.

Finally, rating agencies will react negatively to a 52 percent equity ratio because it (a) would be a deviation from the equity ratios approved by the FPSC for utilities in the state of Florida and (b) would be a downward movement from the equity ratio approved by the Commission for Tampa Electric for the last 11 years. The maintenance of Tampa Electric’s requested equity ratio should lead to adequate coverage ratios and provide the financial strength and credit parameters necessary to maintain the company’s creditworthiness and assure access to capital. Maintaining Tampa Electric’s creditworthiness is also critical in keeping borrowing costs down, which keeps

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customer bills lower.

IV. OTHER ISSUES

Q. In the testimony of FIPUG witness Johnathan Ly, he makes a recommendation related to PTC for Future Solar Projects. Please comment on this recommendation.

A. Mr. Ly indicates that the Commission should ensure that each of the Future Solar Projects entering rate base qualify for PTC.

Each of the solar projects included in the 2025 test year and the 2026 and 2027 SYA qualify for PTC. The company anticipates that solar projects included in future proceedings, beyond the ones included in this proceeding, will qualify for PTC, too.

Q. In the testimony of Mr. Ly, he recommends that the Commission should require that all PTC (grossed up for income taxes) be included as offsets to the company's base revenue requirements associated with each Future Solar Project that is placed into commercial operation and for which cost recovery is authorized. Do you agree with this recommendation?

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A. Yes. For each of the solar projects included in the 2025 test year and the 2026 and 2027 SYA, the company has reduced the revenue requirement for PTC (grossed up for taxes). The company agrees that when the Commission establishes cost recovery for solar projects included in future proceedings, beyond the ones included in this proceeding, PTC (grossed up for income taxes) should be offsets to base revenue requirements associated with each Future Solar Project for which cost recovery is authorized.

PTC are flow through tax credits, and the company has forecasted the use of flow through accounting for solar PTC in the 2025 test year and the 2026 and 2027 SYAs. Each year, the company will continue to use flow through accounting for PTC associated with solar projects.

Q. Should the Commission approve Florida Rising/LULAC witness Karl Rabago's proposal to deny cost recovery for any capital project without a cost-benefit analysis in the record?

A. No. Mr. Rabago's suggestion that the Commission should disallow any capital spending project of $1 million or more that is not supported by a "comprehensive, objective, transparent, and documented BCA" (benefit cost analysis) should be rejected for several reasons.

First, I am not aware of any statute, rule, or FPSC decision imposing that requirement. Imposing that kind of requirement in the middle of a pending rate case would amount to changing the rules after the proceeding has started, which seems inconsistent with traditional notions of fairness and due process and would be better suited to a rulemaking or generic proceeding.

Second, a requirement like that is not needed. Tampa Electric has a robust system of management controls and approvals designed to ensure that the company pursues cost-effective solutions at the lowest reasonable cost. Every funding project for capital expenditures requires management approval, with increasing levels of authorization in the organization as the project proposal crosses designated dollar thresholds. In this proceeding specifically, the company has provided extensive documentation of the analysis and authorization for key projects such as solar generation, the Bearss Operation Center, and others. In addition to individual project approvals, the company's entire capital expenditure budget involves rigorous steps that include internal

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review and Board approval.

Finally, Mr. Rabago's proposal ignores the reality of what circumstances cause an electric utility to install and replace assets. While maintaining our focus on cost discipline and cost effectiveness, the company makes capital expenditures according to the needs of our customers and our obligation to serve.

Three examples illustrate the point: (1) the need to extend infrastructure to new subdivisions being constructed in our service area or upgrade existing substations and conductors in response to load growth, (2) the need to repair and replace property damaged in the normal course of maintaining the equipment and infrastructure of an electric utility (e.g., car hits pole, storm damages transformer, etc.), and (3) the need to comply with changing transportation infrastructure, environmental rules, and safety requirements.

Tampa Electric and the other utilities in Florida do not have time to conduct a BCA when a major transformer fails or when it must extend a line to serve a new subdivision. The company performs projects like these as part of its obligation to serve and to provide quality electric service and does so at the lowest reasonable cost to customers. Requiring a BCA for all capital projects of $1 million or more is simply not feasible from an operating perspective.

Q. The audit report attached to the testimony of FPSC Staff witness Tomer Kopelovich reflects two audit findings. Do you agree with those findings?

A. No. Unfortunately, the schedule of this case did not allow for an audit "exit" meeting, or we would have provided the information set forth below to the staff audit team at that time.

Q. What are the company's concerns with "Finding 1: Association Dues/Economic Development"?

A. Finding 1 recommends a decrease in Association Dues/Economic Development O&M of $748,467 due to the lack of supporting documentation for Edison Electric Institute ("EEI") invoices totaling $745,967 and a Tampa Bay Clean Cities Coalition invoice of $2,500. Tampa Electric intended to provide the supporting documentation for the EEI invoices but missed the selection when providing the documentation as part of the larger audit request. Tampa

Electric was not aware that the documentation was missing, or it would have provided it during the audit. Document No. 3 of my rebuttal exhibit contains all supporting documentation for the EEI invoices.

Additionally, the portion of the EEI invoices associated with lobbying/political purposes was properly excluded from FPSC Adjusted NOI. The Association Dues/Economic Development expense in the EEI invoices was included in FPSC Adjusted NOI.

The Tampa Bay Clean Cities Coalition invoice of $2,500, that applies to the membership period of October 1, 2022 – September 20, 2023, was paid on March 23, 2023. Per Tampa Electric's accounting policies, it was not material enough to warrant prepaid/amortization treatment. Since the Tampa Bay Clean Cities Coalition invoice of $2,500 was paid in 2023, it is correctly reflected as a Historical Prior Year 2023 expense. Document No. 3 of my rebuttal exhibit contains all supporting documentation for the Tampa Bay Clean Cities Coalition invoice.

Q. What are the company's concerns with "Finding 2: Advertising"?

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A. Finding 2 recommends a reduction of $474,843 from the advertising expense reflected on MFR Schedule C-15 due to the inclusion of Conservation advertisements. MFR Schedule C-15 is entitled "Industry Association Dues", and the instructions are to "Provide a schedule of industry association dues included in cost of service by organization for the test year and the most recent historical year. Indicate the nature of each organization. Individual dues less than $10,000 may be aggregated." Tampa Electric's MFR Schedule C-15, "Industry Association Dues," does not include any Advertising expenses. It appears that the auditor intended to cite MFR Schedule C-14, entitled "Advertising Expenses."

Tampa Electric's MFR Schedule C-14, entitled "Advertising Expenses," does not include any Conservation advertisement expenses. In the construction of the MFR Schedule C-14 the 2023 Conservation advertising expenses of $1,744,676 were removed from the total $2,014,460.28 of the 2023 FERC Account 909, Informational and Instructional Advertising Expenses, prior to populating column 1, line 1 of MFR Schedule C-14. Document No. 3 of my rebuttal exhibit contains all supporting documentation for MFR Schedule C-14.

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Q. Should the Commission reduce the company's test year O&M based on Mr. Kopelovich's two audit findings?

A. No. For the reasons explained above, the amounts in question are appropriately reflected in the company's Historical Prior Year 2023 expense.

V. COST-EFFECTIVENESS AND AFFORDABILITY

Q. Intervenor witnesses have commented on affordability of customer bills. Does Tampa Electric conduct its operations with cost effectiveness and long-term affordability of its services in mind?

A. Yes. As noted in Tampa Electric witnesses Jordan Williams's and Marian Cacciatore's rebuttal testimony, the term "affordability" is difficult to define, because it has so many dimensions that are customer specific and beyond the control of the company. The company has to balance many considerations as it provides service to its customers - things like safety, reliability, resilience, environmental compliance, fuel diversity, employee relations, community needs and, of course, the level of our customer rates and the related impact on our customers.

One of the ways we promote affordability is to focus our knowledge, strategic thinking, and experience on cost-effectiveness. The company considers these and many other factors in its planning, its operations, and its financial decisions. This comprehensive approach has helped moderate rate increases in the past and will continue to moderate rate increases in the future.

Q. Can the company control all of the costs that end up on customers' bills?

A. No. Items like the cost of fuel and environmental compliance costs are influenced by market forces and changing legal requirements largely beyond the control of the company. The company is working diligently to implement its FPSC-approved Storm Protection Plan, which over time will reduce the amount of damage caused by storms; however, whether a hurricane or other named storm will hit the company's service area is wholly beyond the company's control. Like our customers, Tampa Electric is subject to the effects of inflation and higher insurance and health care costs, neither of which are within the control of the company. Nevertheless, we remain focused on providing high quality, reliable and resilient electric service at fair, just, and reasonable rates.

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Q. What strategic actions has the company taken with cost-effectiveness and affordability in mind?

A. At a strategy level, the company: (1) invests in assets that generate electricity without incurring fuel costs; (2) continues to install, operate, and maintain assets in ways that improve generation heat rate efficiency, which means less fuel is consumed to generate more power which results in fuel savings; (3) invests in infrastructure that makes our grid more reliable and resilient, which keeps transmission and distribution operating costs lower and reduces the costs of restoring power after major storms; and (4) invests in technology and innovative processes that drive down the cost of serving customers. Evidence of our efforts in these areas and the cost-effectiveness of major capital investments is reflected in the testimony of witnesses Mr. Aldazabal, Kris Stryker, Jose Aponte, Mr. Whitworth, Mr. Lukcic, Karen Sparkman, and Chris Heck.

Q. What operating steps has the company taken with affordability in mind?

A. From an operating perspective, the company: (1) uses asset management principles to execute preventative maintenance and study infrastructure to minimize costs for operating an ever-expanding electric system; (2) prioritizes safety and wellness – which results in a more effective and efficient work force; (3) uses procurement practices that rely on vendor competition, benchmarking, purchasing power, and innovative contracting to mitigate the cost of goods and services; and (4) enables identification and execution of a diverse set of opportunities to produce other operating revenues, which directly reduce revenue requirements. Evidence of our efforts in these areas are reflected in the testimony of the operating witnesses listed above.

Q. What financial steps has the company taken with affordability in mind?

A. From a financial perspective, the company: (1) relies on its financial integrity and market knowledge to optimize access to low cost capital and issue debt at reasonable interest rates; (2) pairs financial teams with business units to train employees and execute controls to maintain financial acumen, which produces value-driven decisions and cost discipline; and (3) optimizes its tax positions to keep tax expense down and provide zero-cost capital funding through deferred taxes. These efforts have produced strong results in areas including investment tax credits, production tax credits and research and development credits. Our efforts in these areas are reflected in my testimony and the testimony of Mrs. Strickland.

VI. SUMMARY

Q. Please summarize your rebuttal testimony.

A. My rebuttal testimony addressed the positions and proposed adjustments for NOI, rate base, capital structure and ROR, CETM, SYA, and tax reform discussed in the testimony of OPC witness Lane Kollen. I also addressed the positions and proposed adjustments for affiliate transactions and allocations in the testimony of OPC witness Bion Ostrander. I addressed the equity ratio proposal reflected in the testimony of FEA witness Christopher Walters. I also addressed three other issues raised by other intervenor and FPSC Staff witnesses and explained how the company manages its activities with cost-effectiveness and affordability in mind.

Q. Does this conclude your rebuttal testimony?

A. Yes.

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BY MR. WAHLEN:

Q Mr. Chronister, did you also prepare and cause to be filed with your direct testimony an exhibit marked JC-1, consisting of two documents?

A Yes, I did.

Q And did you adopt the exhibit now marked as JC-2, consisting of five documents, on May 2nd?

A Yes, I did.

Q And did you prepare and cause to be filed with your rebuttal testimony an exhibit marked JC-3, consisting of three documents?

A Yes, I did.

Q And have you prepared some updated MFR schedules in this docket?

A Yes.

Q And they have been submitted?

A Yes.

Q Okay. Thank you.

MR. WAHLEN: Mr. Chairman, Tampa Electric would note for the record that the Exhibits JC-1, 2 and 3 have been identified in the Comprehensive Exhibit List as Exhibits 31, 32 and 151.

CHAIRMAN LA ROSA: Okay.

BY MR. WAHLEN:

Q Mr. Chronister, would you please summarize

your prepared direct, adopted and rebuttal testimony?

A Sure.

Good afternoon, Commissioners. I have two sets of direct testimony. My original direct testimony was filed on April 2nd, 2024. The second set, which was originally filed by Richard Latta, was adopted by me on May 2nd, and I refer to this as Chronister II.

My original direct testimony explains how the company's financial profile has changed since our last rate case; explains the importance of the company's financial integrity and credit ratings; presents the company's proposed capital structure and weighted average cost of capital for the test year 2025; explains why the Commission should approve our 54 percent equity ratio; and explains why the Commission should approve our proposed subsequent year adjustments for 2026 and 2027, as well as provisions for income tax changes, storm cost recovery and asset optimization.

My Chronister II direct testimony explains why 2025 is a reasonable test year for our proposed January 2025 base rate increase; explains our 2025 budget process and the -- or our budget and the process used to develop it; presents the calculations for our 2025 rate base, net operating income and revenue requirements; explains how we account for affiliate transactions, and presents the details of our proposed 2026 and 2027 subsequent year adjustments.

I filed rebuttal testimony on July 2nd, 2024. My rebuttal testimony responds to each of the adjustments and affiliate transaction recommendations proposed by OPC; explains why the Commission should not approve FEA's proposed equity ratio; addresses three other issues raised by the staff auditor and other interveners, and summarizes some of the actions the company takes to promote the long-term cost-effectiveness and affordability of our electric service.

Additionally, my rebuttal testimony discusses the importance of financial integrity and credit worthiness at Tampa Electric. Given the fact that Tampa Electric issues its own debt, a downward movement from a 54 percent equity ratio that the Commission has authorized for the company since 2008 would cause the rating agencies to react negatively, which could adversely affect the company's borrowing costs, which would increase the company's cost to serve our customers.

My testimonies and exhibits reflect the company's efforts related to cost discipline and affordability. Two examples of this are that our 2025

O&M expenses are $70 million below the Commission's benchmark, and the company's 2025 jurisdictional adjusted income tax expense is a negative number. It is negative $8 million. This is primarily due to the Company's tax credits for in-service assets, the production tax credits and the investment tax credits.

The revenue requirement benefit for these credits over the three years from 2025 to 2027 will be a reduction to customers' bills of roughly a quarter of a billion dollars.

This concludes my summary.

MR. WAHLEN: Mr. Chronister is available for cross-examination.

CHAIRMAN LA ROSA: Thank you.

OPC, you are recognized when you are ready.

MS. CHRISTENSEN: Yes, Commissioner -- or, Chairman, excuse me. We have a small, hopefully, housekeeping issue before I start my cross-examination.

CHAIRMAN LA ROSA: Sure.

MS. CHRISTENSEN: There were a few -- two exhibits that had not made it into our documents that we submitted to the Commission, and we had submitted a revised filing with these electronically last Friday, and per instructions, we have prepared 20 copies to be handed out at the hearing. Would you like me to distribute those now, or at the time? How would that -- how would you like me to handle that?

CHAIRMAN LA ROSA: I just want to make sure I understand what -- so they did not make it into the Friday's filing?

MS. HELTON: And part of the issue, you know, and why we did not add them to the CEL and to what was filed in Case Center was because we were unsure of -- as you know, the Order Establishing Procedure and the Prehearing Order set a date certain by which cross-examination exhibits were to be submitted to the Commission so that we could load them up, but there is an exception there for good cause. If there is, for some reason, the exhibit was not available at the time of the filing. So I am not sure that I am appreciative or understand what the good cause is for these exhibits.

CHAIRMAN LA ROSA: Sure. So could I ask that?

MS. CHRISTENSEN: Well, I would say this, that this was an inadvertent -- with the large volume of documents that we had to produce, we inadvertently omitted these two exhibits that should have been included. We are just asking to be treated consistent with the other parties, you know, staff uploaded all of the documentation for the CEL on Thursday and Friday, and the company produced an amended filing that was added to the CEL last week, on Thursday, that's been included in this proceeding, that -- for information that was available since the beginning of August. So we are just asking for fair treatment and being allowed to use this documentation.

CHAIRMAN LA ROSA: So I am okay with allowing that in, but there is a reason why there is a good clause -- a good cause in when we discussed at Prehearing.

MS. HELTON: And my concern, those of you who know my boss, one of the things that he often says is no good deed goes unpunished.

CHAIRMAN LA ROSA: Right.

MS. HELTON: And so that is my concern in that if we allow this now, then will people take the requirement to provide exhibits by a date certain seriously?

I am going to give everybody a pass. This has been a learning experience, Mr. Chairman. I just hope that in the future that we can -- now that we kind of understand the process, and understand what we are dealing with, that we can all work towards getting the information to us in a timely manner so that we can -- everyone can be on notice as to what the exhibits are, and so that we can effectively use the Case Center system.

CHAIRMAN LA ROSA: Yeah. And --

MS. HELTON: And it is my understanding, I think, that Mr. Wahlen did not object to this either, so -- but I don't want to speak for him.

CHAIRMAN LA ROSA: Yeah. I don't see objections, but I do want to reiterate the point, is that if I allow this to be entered now, I don't want this to be the precedent.

I know that Case Center has -- we have been using it well, and it's been working very well this week. It's been a rollout that's taken us a little time, but I think we are there. And I think there is reasons why we have done that. And I hopefully those are proven throughout this week.

So I will allow it now. I just, again, just want to make sure that it's understood, that I am saying that this isn't the precedent moving forward.

MS. CHRISTENSEN: Well, we certainly commit to -- I think we had some discussions at the

Prehearing about having a workshop to discuss the Case Center, and how that's working out, and how it can be implemented better, and some of our objections to certain things that are processes. And we will certainly agree to discuss that and try to resolve it as part of that Case Center workshop. And I think that would be a good place for it, and I appreciate the accommodation today.

CHAIRMAN LA ROSA: Yeah. Absolutely. And I will, just to say on the record, that I agree with our Prehearing Officer on the workshop, and we will do that, and I think it will be a great time to be able to look back after this hearing process and unpack a little bit and provide even better guidance.

So let's go ahead distribute that, and we can move forward with questioning.

MS. CHRISTENSEN: Yeah, if you would give us a few minutes, we will have these passed out shortly.

CHAIRMAN LA ROSA: Sure.

MS. CHRISTENSEN: Thank you.

MR. WAHLEN: Thank you.

MS. CHRISTENSEN: Commissioner, whenever you are ready, I think we are.

CHAIRMAN LA ROSA: Yeah, I think we are ready.

Let's jump right in.

EXAMINATION

BY MS. CHRISTENSEN:

Q Thank you, and good afternoon, Mr. Chronister.

A Good afternoon.

Q I would ask to have you take turn to page eight of your direct testimony.

A Very good. Okay, I am there.

Q Okay. And this is where you say that TECO has grown rate base by 2.2 billion, or nine percent per year, is that correct?

A Yes.

Q And the rate base increases result in an approximately $555 million revenue requirement impact all including higher depreciation rates, O&M expense, taxes other than income taxes and cost of capital; correct?

A The figure you just said there, where is that figure?

Q I am sorry. Let me move on to another set of questions. We will just go further on that. Let me change your attention to page 13 of your testimony.

A I am there.

Q Okay. And starting at line 10 of that testimony -- one second. Okay. This is where you

discuss the impact of inflation on the company during 2022 through the 2024 period, correct?

A   That's correct.

Q   And you say that general inflation increased the price of -- prices that TECO pays for the goods and services it uses to provide services to customers, correct?

A   Yes.

Q   And am I correct that as an example of this inflation, you cite a 40-percent increase in transformers, 36-percent increase in substation equipment, 21-percent increase in switchgears and 34-percent increase in poles?

A   Yes. That's correct.

Q   And then on page 14, which I believe is the next page, you go on to discuss the -- you go on to discuss and say that the company focused on decisions to counteract the upward cost pressures on 2025 O&M expense levels, correct?

A   That's correct.

Q   And then further on, on page 15, and starting at line 12 of your testimony, is it correct that you talk about the growth in capital investments which provides opportun --

A   Did you say 12?

Q Yes, I believe page 15, line 12, there is a bullet three.
A Very good. Yes.
Q And this is where you say: The company recognizes that with the growth in capital investments comes the opportunity to appropriately charge a greater amount of Administrative and General Expenses to capital; is that correct?
A That's correct.
Q And in this case, this switch to capital comes at a price tag of approximately 10 million, correct?
A I don't understand your question.
Q Let me rephrase that.
The change from A&G expense to capital is a shift of approximately $10 million that is now being capitalized, correct?
A Yes. This is talking about us increasing the amount of our A&G expenses that we then credited out of expense and debited to capital.
Q Okay. And A&G -- if it remained in A&G expense, that would be expensed in a single year, correct?
A Correct.
Q Okay. And so it would be right that the 10 million in A&G capitalization expense that is now

included as capitalized in rate base are going to be collected from customers over a longer period of time than usually would occur if it was expensed during the year, correct?

A Correct. The A&G capitalized would become part of the asset value, and then it would be in depreciation expense, and, you know, one-thirtieth or one-thirty-fifth of the amount as opposed to that expense being in, for instance, the test year at a full $10 million.

Q Okay. And when you say one-thirtieth the amount, that means it's going to be collected over the next 30 years?

A I -- what I was saying was, is if you capitalize expense and it becomes part of the asset value, then expenses only hit by a fraction of one-thirtieth each year, as opposed to the 10 million.

Q Right. And then the corresponding amount that's been capitalized, one-thirtieth will be collected for the next 30 years, is that correct?

A Yes.

Q Okay. I would ask to have you look at OPC 121.

A Okay.

Q Give it a second. It should pop up.

Okay. And this is the U.S. Bureau of Labor & Statistics. Are you generally familiar with Consumer Price Index summary?

A Yes, generally.

Q Okay. And if we look down the document, this talks about the percentage change in CPI for all urban customers, would you agree with that?

A Yes, it appears to do that.

Q Okay. And if you look under electricity, do you see where it shows an unadjusted 12-month ending July 24, percentage of 4.9 percent?

A Hang on a second. On this screen, I think it has the beginning of the document. It doesn't have that page.

Q Okay. If you scroll down, you should be able to get there.

Okay. Do you see where it says, electricity?

A Yes, I do.

Q Okay. Yeah. And if you go across to the last column, do you see where it says, unadjusted 12 months ended July 2024?

A Yes, I do.

Q Okay. And you would agree that the percentage that's shown there is 4.9 percent, correct?

A Yes.

Q Okay. Now I would like to show you document OPC-146. And it will pop up on your screen shortly? Mr. Chronister, it should be up on your screen right now. Do you see that?

A I do.

Q Okay. And are you familiar with this late-filed exhibit response? Was this provided by you?

A Yes.

Q Okay. And this exhibit shows the dividend payments made by Tampa Electric to its parent, TECO Energy, is that correct?

A That's correct.

Q Okay. And looking at the second bullet in your discovery response, this says that TECO Energy -- or Tampa Electric pays 100 percent of its net income to TECO Energy, correct?

A That's correct.

Q Okay. And then go down to the fourth bullet on this document. It says that when Tampa Electric pays 100 percent of its net income -- I am sorry. The fourth bullet says that when Tampa Electric pays TECO Energy the dividend, Tampa Electric transfers the cash from the company's bank account to TECO Energy's bank account, correct?

A That's correct. I just wanted to add

something. On the bullet you had me read, that sub-bullet underneath of it is also important to note. It reads: This procedure allows for a clear line of sight related to equity infusions made by TECO Energy to Tampa Electric.

In other words, the reason that we dividend 100 percent of net income up is so that the equity injections that come from the parent company are clear in terms of the equity injections coming from the parent.

Q Okay.

A That's why we have done it that way for decades.

Q Right. But either way, 100 percent of your net income goes back up to the company, correct?

A Yes.

Q Okay. And Tampa Electric doesn't pay Emera dividends, correct?

A Tampa Electric does not pay Emera dividends, no.

Q But it would be fair to say that TECO Energy does pay Emera dividends, correct?

A TECO Energy would pay dividends up to Emera US Holdings Company, which would then pay dividends up to Emera.

Q Okay. Fair enough.
I am going to ask you a few questions that were referred to you. Let me see if I can find a better place to ask these.
Okay. You have testimony on page 57 of Mr. Latta's direct testimony that you adopted, if we can get there.
A Yes. I do. I am there.
Q Okay. Give me a minute. I am just waiting for my direction to pop up. There we go.
Okay. And I believe in this portion of his testimony, he talks about the subsequent year adjustments, is that correct?
A Which line?
Q Hold on. Are we in Mr. Latta's testimony?
A Yes. Chronister Roman numeral II. Page 57 has cost allocations.
Q Well, I think -- I want to say I think maybe your testimony popped up, not Mr. Latta's testimony.
A Okay.
Q That may be the confusion. Chronister, what, II?
Anyway, you would agree that Mr. Latta's testimony discusses the subsequent year adjustments, correct?

A Yes. That's correct.
Q Okay. And in his testimony, he talks about several projects that will come into service during 2025, but will not reflect a full 13-month average cost until 2026, is that correct?
A Yes.
Q Okay. And am I correct that these projects are Polk 1 Flexibility Project, three of the battery storage projects, Corporate Headquarters, the Bearss Operations Center, part South of the Tampa Resiliency Project, two of the solar projects, and multiple individual projects under the GRR, correct?
A That's correct. As you noted, there is some 13-month average for these projects in 2025 because they go in service in the middle of '25, but then you don't get a full 13-month average of those projects until the following year. So this is the incremental amount of the asset.
Q Okay. And then those would be part of your 2026 subsequent year adjustment request, correct?
A That's correct. So to your point, on Document 5, the 2026 section is for assets that go in service in 2025.
Q Okay. And it would be true that the projects that are expected to go into service in 2026 and impact

2027's SYA are a portion of the Polk Fuel Diversity project, portions of the South Tampa Resiliency Project, and then multiple other projects under the GRR, and approximately four solar projects; correct?

A That's correct. Just a point of clarification, it's the 2027 GRR would just involved three GRR projects.

Q Okay. But that's a few projects, right?

A Yes.

Q Okay. Isn't it true that you are claiming that without additional '26 and '27 rate relief with all the plant additions that TECO is planning -- oh, I am sorry. Strike that question.

Let me take you to page 44 of your Chronister direct testimony.

A I am there.

Q Okay. Let me just give it a second and let me see what pops up.

A Yes, I am there.

Q Okay. And looking at lines 19 through 22, this is where you discuss -- where you say that without the '26 and '27 SYAs, TECO expects to earn below the bottom of your requested range in 2026 and 2027; is that correct?

A Yes.

Q Okay. And this statement assumes no additional revenues beyond 2025, is that correct?
A It assumes the revenues that would come from customer growth --
Q Okay.
A -- and other revenues that would be projected by witness Lori Cifuentes.
Q Okay. But nothing above what was included in the rate case, correct, no additional revenues?
A Correct. It assumes that the SYAs would not be there.
Q And you would agree that this assumes that all the projects would go forward on the schedule presented in this case without any delays, correct?
A Yes.
Q Isn't it true that there is no requirement that even if you receive the revenue for projects, that TECO must -- that there is a requirement that TECO must proceed with those projects on the schedule represented at this hearing?
A I don't think there would be a requirement. I think there would be an expectation on the part of the Commission that if SYAs were granted in this case, that TECO would certainly have an obligation to complete those projects.

Q Okay. But I think you agreed with me that there is no requirement?

A No.

Q Okay. And you would agree that there were projects that were deferred -- and this is a question that referred to you, and it's regarding the projects that deferred from 2023 and 2024. Do you recall those questions?

A Yes, I do.

Q Okay. So my question to you is: If the deferred 2023 and 2024 capital expenditure projects were placed into service as originally planned, would you agree that the effect on the '25 -- 2025 test year would be a lower rate base due to the recognition of additional accumulated depreciation, with all other things being equal?

A Yes. And let me --

Q Okay.

A -- make sure that I understand your question.

You are saying that if we had placed those assets in service in '23 and '24, they would be in the rate base, they would reflect a little bit of accumulated depreciation, one-thirtieth, one-fortieth of that depreciation, and so there would be a slightly lower amount if they had been put in service a couple years earlier.

Q Due to the accumulated appreciation --

A Yep.

Q -- correct?

A Yes. Exactly.

Q And would you agree that TECO was given the revenue requirement to cover these deferred 2023 and 2024 projects in the '21 TECO settlement?

A No, I don't agree with that. When Mr. Kollen was talking about the deferral of projects, he was not referring to the GBRA projects.

So the GBRA projects in the '21 settlement were the Big Bend modernization and some solar facilities. All of those assets were placed in service as we had discussed in the '21 settlement. Mr. Kollen was referring to other capital projects that were deferred.

Q However, you were and you did agree to a revenue requirement amount in the '21 settlement that was to cover period from 2021 through the end of 2024, correct?

A Yes, but --

Q Okay.

A -- it's important --

Q Thank you.

A Okay.

Q Would you also agree that for the approved solar projects in this rate case, there would not be a true-up mechanism if a project were delayed or not built for any reason?

A Yes.

Q Okay. And you are aware, the 2026 and the '27 SYA includes the GRR projects, right?

A Yes.

Q And looking at page 45 of your testimony, which I believe is the next page. On lines five through 10, you claim that Tampa Electric's 2026 and 2027 SYAs are not being proposed to recover general expense increases and routine capital expenses, correct -- or capital additions. I am sorry, correct?

A That's correct, because the SYAs are for specific assets, which is similar to the GBRAs from the '21 settlement, the GBRAs were related to specific assets --

Q Okay.

A -- so routine capital additions would not be part of a GBRA or an SYA.

Q Okay. And we are going to explore that a little bit more.

To your knowledge, has FPL or Duke ever sought

and/or had approved recovery of distribution capital costs through an SYA?

A Not to my knowledge.

Q Okay. And are you aware that prior -- or are you aware that prior requests by Tampa Electric for SYAs have been base rate -- or generation base rate adjustments for new generation assets exclusively?

A Not exclusively. We also had a rail spur that brought fuel to Big Bend station that was also a part of a subsequent year adjustment.

Q Okay. Was that done in the fuel clause, or was that done as a step increase?

A Part of -- it was a step increase from the 2008 rate case.

Q Okay. And that was part of a settlement?

A No. That was a litigated case.

Q Okay.

A It was the last time I sat in this chair.

Q Yes. 10 years --

A 16 years.

Q 16 years ago. That's quite a history.

Isn't it correct that along with the other senior leadership within Tampa Electric, you made the decision to move from the prior practice of GBRAs only to SYAs that include new distribution capital projects?

A No. I -- we stayed consistent in that each time we have proposed a GBRA or SoBRA, it's because we were putting in specific assets that were material enough that if we did not get subsequent year recovery of revenue, it would have brought the company in sooner for rates.

Q Okay. And those GBRAs and SoBRAs are related to generation facilities, correct?

A Yes. Each of the GBRAs and SoBRAs were related to generation.

Q Okay. You would agree that the request for the SYA for new distribution capital projects is a historic change in the way the distribution capital costs are recovered?

A I would not agree with that.

Q Okay. Isn't it true that Tampa has never sought recovery of distribution capital costs through an SYA?

A Yes, that's true.

Q Would you agree that there are no written guidelines for the selection process of these projects that are included in the SYA?

A When you say written guidelines would it be written guidelines of the company or written guidelines of the Commission?

Q Specifically, the company doesn't have any written guidelines as to how to select for projects that were included in the SYA request?

A Correct.

Q Okay. And the company chose projects to include in the SYA for transformative aspects of things, as well as material impact on financial integrity and return on equity; is that correct?

A Yes.

Q Okay. So Tampa considered a project material if the basis point impact of having the asset and all equity support of that asset was big enough that it would take TECO below the bottom of the allowed range, is that correct?

A Yes.

Q And the range you were using for this determination was your proposed 11.5 percent ROE request, plus to minus 100 the basis points, is that correct?

A No. I can explain.

The Commission has traditionally established a midpoint, and then had plus or minus 100 basis points from that midpoint, and so regardless of what the Commission chooses at the midpoint in this case, I am expecting that it would be plus or minus 100 basis points.

We have talked about earlier in this hearing that about 60 million equates to about 100 basis points. And you can see that the revenue requirements associated with the 2026 SYA is 100 million. And so that would take us 150 basis points below the midpoint. So if you moved 150 from any midpoint, you would be below the bottom of the range.

Q Okay. But that's -- my question was: In choosing the programs that you included, you used the 11.5 as your reference point for the midpoint, correct?

A No.

Q Then what did you use?

A Any ROE. In other words, you can -- if you do the math, say, well, if they set it at 11.50 and ROE degrades -- and the bottom is at 10.50, and ROE degrades 150 basis points you would be below. If they set it at 10.50, and 100 basis points below is the bottom, and you degrade by 150 basis points, you would be below as well.

So we didn't use 11.50 in the evaluation. We used the basis point impact and ROE of the revenue requirements associated with specific assets.

Q Okay. But the amount of revenue requirement needed to support that particular project would change based on whatever ROE is approved in the case, correct?

A Yes. The company agrees with that.

Q Okay. Let me show you OPC Exhibit 150. And are you familiar with this document?

A I am sorry, I was just waiting for it to come up.

Q Sure. And when it does, let me know.

A It's up.

Q Are you familiar with this document?

A Yes, I am.

Q Okay. And this shows the basis point impact that you were referring to?

A Yes.

Q Okay. And just -- I want to go to the first page of this exhibit, to the first schedule. Do you see that?

A Yes.

Q And I just wanted to confirm, is this the most recent up-to-date summary of the 2026 and '27 SYAs?

A No. This is a late-filed exhibit from my deposition. And then when we contacted the parties and informed that the PTC rate had gone higher, these dollar amounts have come down.

Q Okay.

A That was part of the August 22nd letter that is sent.

Q Okay. And so would the most current and up-to-date SYA summaries be included as part of that August 22nd, 2024, filing?

A Yes. So the new SYA proposals with the lower amounts for the removal of GRR, the higher PTC rate and the other items that we agreed to, the 2026 number would be 92,373,608, and the new number for '27 would be 65,473,847.

Q Okay. And those are the numbers that we should rely on for any adjustments or if we are going --

A Yes, exactly.

Q Okay. I would like to ask you about your direct -- or, I am sorry, your rebuttal testimony, page eight.

A Did you say page eight?

Q Yeah.

A I am there.

Q Okay. And I think, for the most part, we should be talking direct test -- or rebuttal testimony, except for a few questions. I am moving to that.

Okay. On page eight of your testimony, rebuttal, you talk about OPC's proposal to correct the company's failure to capitalize its pension and OPEB expense, correct?

A Yes.

Q Okay. And I would ask to have you look at the Exhibit No. LK-4 that was attached to Lane Kollen's testimony?

A That will come up on the screen?

Q Yes.

A Okay.

Q Hopefully shortly.

A Yes, I see it.

Q Okay. And this is an interrogatory response that you sponsored, correct?

A That's correct.

Q And in a response, under Sections A and B, you say, the pensions and the OPEB expenses are initially posted to FERC Account 926, and shown on MFR C-17, correct?

A Correct.

Q And this is your actual accounting, correct?

A Yes.

Q Okay. And then you say that the pension and OPEB costs are capitalized through the fringe rate in this response, correct?

A Yes.

Q Okay. And then it's offset -- the capitalization and the fringe rate, you claim to post a credit, to the FERC Account 926 to offset the initial

posting, am I correct in that?
A Did you say propose? Is that the word you used?
Q Posting. I can repeat the question if that would help.
A No, that's okay.
The way to explain it is this: We post all of our benefits expenses to 926 because the Uniform System of Accounts requires it to go to 926. When you make -- the FERC accounts allow you to use 922 and 929 for other expenses that you credit against O&M. But when it comes to 926 expenses, you do the credit inside of Account 926.
Q Okay. So I think I am correct that you post the credit to the FERC 926 to offset the initial posting you made once you implement the fringe credit.
A (Witness nods head in the affirmative.)
Q Okay. Let me move to my next question.
In response to this interrogatory, you did not provide any documentation that showed the crediting of Account 926 for the capitalization charged through the fringe rate, correct?
A Correct. This interrogatory asked to explain --
Q Okay.

A -- what happened, not provide the detailed calculations.

Q And would you agree that the actuarial report does not show capitalization of pension and OPEB, correct?

A That's correct. What happens is the actuary sends us the benefits expenses that we need to book. We debit the 926 account for those benefits expenses. Meanwhile, the company has a fringe rate. So when labor is charged to capital, when the fringe follows it, you debit that capital account and you credit the 926.

And the reason to do that is it allows you to make those original debits and see the original whole benefit cost to be able to judge whether that benefit cost is reasonable.

Q Okay. Well, given that, in other words, if the company's actuarial report amounts and the amounts in 926 match for pension in OPEB and the -- let me start the question again. Tongue-tied.

In other words, the company's actuarial reports amounts and the amounts in Account 926 match for the pension and the OPEB, and those would be pre-capitalization amounts, correct?

A Yes. Let me --

Q Okay.

A -- make sure I explain --
Q Well, I mean --
A -- because I think you said -- I think you said MFR. I just wanted to make sure.
Q No, I didn't say MFR.
A Okay.
Q I did not.
A All right. If you could repeat the question then?
Q I just said, in other words, if the company's actuarial report amounts and the amounts that are in Account 926 for pensions and OPEBs are the same, those would be recapitalization amounts, correct?
A Yes. Sorry.
Q That was a little clearer.
Let me ask you to look at the document we passed out that's labeled Late-filed Deposition Exhibit 1.
A Is it OPC 242?
Q It is labeled, Late-filed Deposition -- or Late-filed Exhibit No. 1. This is a document that we passed out. It may be at the top of the table.
A Yeah. It just says --
Q Okay.
A -- that on the corner.

Q Yeah, it may. Mine does not have the cover page.

But anyway, this was the documentation that you provided in response to a question that was posed to you?

A Yes.

Q And this was -- you were asked to provide exhibit that shows the total OPEB and pension amounts capitalized for 926, correct?

A Yes.

Q Okay. And would you agree that this late-filed exhibit does not show any credits to Account 926? If you flip it over to the other side, it's not showing any credits that were posted to Account 926, correct?

A No, it does. The credits are the pension costs capitalized is -- oh, it's not on the screen.

So in the section that says, pension costs capitalized, amounts charged to other balance sheet accounts, remaining pension cost excluding SERP restoration included in final O&M.

So in other words, what this is doing is it's showing you the amounts that got capitalized.

Q All right. But it doesn't show the amounts that got credited to Account 926, correct?

A No, it does. In other words, the $424,000 of pension, and the $697,000 of OPEB -- or, excuse me, post retirement medical expense capitalized, those are the credits to 926.

Q Okay. And so if we looked at Account 926, when we asked for an exhibit of that, would it show as a posting as a credit in Account 926? That's what we asked for, and this is not showing those as postings to Account 926, correct?

A Yeah. The way our accounting systems work is that the fringe benefit postings follow labor, and then the other side of the transaction, where you reduce 926, is the total amount of all the fringe that got credited against 926.

So when -- in your -- in my deposition, when you were asking about us capitalizing costs, you said, could you explain that and also show it? And what we did here is we showed the amount capitalized through the fringe process.

Q Okay. So you created a document, but you didn't produce the ledger or the account where it showed the actual credit, is that correct?

A We did not produce the documents inside the system because there is no posting that's individualized by benefit type.

Q Okay. Let me take you to a different issue. And on, I think in your direct testimony -- or no, I am sorry, I think we are still in your rebuttal testimony, starting at page 21.

A 21 of my direct?

Q No. I am sorry. Your rebuttal.

A Okay.

Q Originally we were keeping them separate, and now we have got them together so I am trying to remember which questions I am on. And I believe that --

A What page from my rebuttal?

Q 21 of your rebuttal.

A I am there.

Q Okay. As soon as it gets me there we will be there.

Okay. Starting at line four, this is where you discuss that the environmental restoration cost for solar should be allowed as reasonable, correct?

A Yes.

Q And you would agree that Mr. Kollen's position is that not all the costs included in Mr Kopp's dismantlement study related to solar are reasonably known and measurable, correct?

A Can you repeat that question?

Q Would you agree that Mr. Kollen's position is

that not all of the costs included in Mr. Kopp's dismantlement study related to solar dismantlement are reasonable -- reasonably known and measurable?

A I agree that that's Mr. Kollen's position.

Q Okay. And you do not address Mr. Kollen's criticism of Mr. Kopp's testimony, such as failure to review leases, or the requirements that might impact dismantlement, right?

A I did not address that issue in my rebuttal.

Q Okay. It would be true to say that Mr. Kollen's criticism is addressed, and has been addressed by Mr. Kopp's testimony, correct?

A Yes.

Q Okay. And you would also agree that the specific steps needed for solar site remediation is not within your area expertise?

A That -- say that question again.

Q In other words, you are not an expert in solar site dismantlement, are you?

A No, I am not an engineer or an operations person, but I do make sure that I account for the costs associated with the remediation.

Q And I will happily accept that you are an accounting expert when it comes to accounting appropriately for those costs.

A Thank you.
Q Now, you would agree that TECO has only had solar facilities since 2017, correct?
A We had a few smaller facilities before that.
Q But the major solar -- utility scale solar was started --
A Began and came on-line in 2017, yes.
Q Okay. And TECO has done any large scale dismantlement for solar facilities, correct?
A No.
Q Okay. And you would agree that TECO does not know all of the dismantlement activities that will occur for these solar facilities at these time, correct?
A We don't know them because they haven't occurred.
Q Okay.
A Only would be able to forecast them.
Q All right. Fair enough.
Let me take you to your rebuttal testimony at page 23.
A I am there.
Q Okay. Let me make sure I am at the right spot.
Okay. And this is where you talk about the deferred PTCs' amortization period, correct?

A Yes.

Q And you claim that OPC's proposed three-year amortization period for the deferred PTCs would create an abnormal expense reduction and enhance the need for rate relieve at the end of three years, is that correct?

A Yes.

Q You would agree that PTCs are earned and used to reduce income taxes in the same year, right?

A The PTCs that we earn in the year 2025 and beyond will be flowed through. But the PTCs that were earned from '22 to '25 were subject to the '21 settlement agreement.

Q All right. Well, let's just talk about PTCs in general and '25 as a reference point. Those PTCs are earned and used within the same year, correct?

A Yes.

Q Okay. In fact, you are including 30 million in PTCs credit in '25, which is based on the energy produced for all the solar assets placed in service in 2022 as a reduction to the 2025 test year, correct?

A That's right.

Q Okay. And then if we look at page 24 of your rebuttal testimony.

Okay. If you look at page 24, and when you start at line one. You offer a counterproposal of

five-year amortization period for PTCs, correct?

A Yes.

Q Okay. And if the Commission were to approve the five-year amortization period, you say the 2025 NOI adjustment, after applying the jurisdictional factor and gross revenue -- the gross-up multiplier would be a reduction of 5.52 million. Is that amount still correct?

A No. So let me explain how that number would change.

As Witness Strickland said earlier, PTCs are earned in the first 10 years that the solar is in operation. She also mentioned that PTCs were better than ITC.

As an example, if you have $55 million ITC at the beginning of a project when it goes in service, and instead you had PTCs of $8 million, you would earn them each year. Eight million a year for the first 10 years would be $80 million. A much better benefit for the customers.

Q I think, Mr. Chronister, we may have gotten a little off track from what my question was.

A I understand what you are saying. I am just trying to explain why this 5.5 would change.

So during the course -- during the three years of the settlement period, since the settlement agreement said that new tax credits would flow to customers in our base rates on a normalized basis, then the company's original interpretation of that was that that be over the life of the asset.

In our conversations with the other parties, including OPC, a suggestion was made by OPC that 10 years would be better because that's the period of time that you are earning PTCs.

So this 5.5 million is the 55 million divided by 10 years. But now that the PTC rate has gone up, we expect a year-end number for PTCs during the three-year period to be 58 million. So this would go to 5.8 million.

Q Okay. And your discussion, we are talking essentially about the deferred PTCs that were from the period 2023 through 2024?

A '21 to '24, yes.

Q Okay.

A The deferred -- the regulatory liability for the deferred benefit of the PTCs.

Q Okay. I believe that's '22 through '24?

A What did I say?

Q You said '21. That's why I was confused.

A Sorry.

Q Okay.

A '22 to '24.

Q Okay. And I'm -- so essentially, the counterproposal that is in your testimony, if updated for a five-year period, would be 5.8 million; is that my understanding of your testimony today?

A Yes.

Q Okay. And was that amount affected at all by the change in the new PTC credit from $2.75 to $3?

A Yes.

Q Okay.

A There was 55 million, and we had proposed to do it over 10 years, so it would be five-and-a-half. By shortening the amortization to five years, it doubles the five-and-a-half. So if you take 58 million over 10 years, it would be 5.8. But if you use five years, that 5.8 would then go to 11.6.

Q Okay. So the five-year proposal with the new credit amount would essentially be 11 --

A Right. This is the differential.

Q Okay.

A So it just -- it just so happens because it's 10 and five years, that this would have been 11 million -- 11.4 million --

Q Okay.

A -- and now it would be 11.6 million.

Q Okay. Thank you for that clarification.

On page 30 of your direct test -- oh, I am sorry, your rebuttal.

A Okay.

Q We are going to be in your rebuttal hopefully for most of this.

A Page 30?

Q Page 30. Uh-huh.

A I am there.

Q Okay. Great.

And starting on line 10, you start talking about the Grid Reliability and Resilience Program.

A Yes.

Q Okay. And you are aware that Mr. Kollen and Mr. Mara, OPC witnesses, opposed your proposal to recover the cost of certain grid reliability and Resiliency projects in 2026 and 2025?

A Yes, I am aware of that.

Q Okay. And you claim that even though those are not generation assets, the Commission should approve these groups of individual projects because it will mitigate against the need for a full rate case in 2026 and 2027?

A Right, the four specific assets that Mr.

Lukcic testified to, the revenue requirement, if it's absent, would create degradation to ROE.

Q Okay. You would agree, though, that the 2025 test year is supposed to be representative of costs going forward, correct, when you chose the test year?

A Yes.

Q Okay. And if we go on to page 31, you would agree that the SYA's purpose should be to allow cost recovery for future major projects, correct?

A Yes.

Q And you are not aware of any other utility, including Tampa, that's ever sought to recover transmission and distribution projects --

MR. WAHLEN: Asked and answered.

MS. CHRISTENSEN: -- included in SYA?

MR. WAHLEN: Asked and answered.

CHAIRMAN LA ROSA: Sustained.

BY MS. CHRISTENSEN:

Q You claim that the GRR program is a major project, but isn't it correct that it's actually a grouping, I think we've said of 40 or so individual projects that were recently reduced in the August 22nd, 2004 filing by about two projects?

A No. The 40 projects that you are referring to is all of the projects that are in the seven-year GRR program that runs through 2030.

The -- in our filing in the SYA, we only selected four GRR components to put in service, and two of them are already over the amount of $50 million to be eligible for AFUDC; but it's 27 million, 24 million, and then two projects that are over 50 million apiece.

So when you remove the two projects -- there were six in there, and we removed two smaller ones, so that the only thing left are the four projects that add up to about 159 million.

The 40 projects you are referring to is the seven-year total that the company is not asking for this particular proceeding.

Q Okay. So you -- would you agree that Mr. Kollen opposed the company's request to include the GRR cost in the '26-'27 SYA without sufficient guidelines and rules, and the Commission should -- and he recommended that the Commission should establish parameters or guidelines to assess whether to approve your request, or deny your request, or even modify your request?

A I am aware that that was Mr. Kollen's position.

Q Would you also agree that Mr. Kollen proposed guidelines and parameters in his testimony?

A Yes. I am aware of that.

Q And you did not rebut or oppose those parameters or guidelines in your rebuttal testimony, nor did any other Tampa witness, correct?

A That's correct.

Q And isn't -- in fact, isn't it true the Commission approves -- that if the Commission approves the money GRR '26 and '27, the company is under no statutory obligation or Commission requirement to spend the money on those GRR projects, correct?

MR. WAHLEN: That's been asked to answer as well.

MS. CHRISTENSEN: I don't think we asked about the GRR projects.

CHAIRMAN LA ROSA: Let me go to staff on that --

MR. WAHLEN: I withdraw the objection. He can answer the question.

THE WITNESS: Yeah, I would answer it the same way on all the SYA projects, as well as the GRR project, there would be no statutory requirement to complete them, but the company would certainly feel the obligation and responsibility to complete them, just like we have the other base rate adjustments.

BY MS. CHRISTENSEN:

Q So if the company were to decide to defer these projects to be completed later in '28 for some reason, as long as the company was earning under the top of the range, the company would be able to keep its money, or be able to keep that revenue requirement if it was granted by the Commission, correct?

A Under the structure of your question, yes.

Q And I think I am going to direct you for a short period back to direct testimony, and I believe it's on Mr. Latta's testimony on page 53.

A Chronister II, yeah.

Q I am talking about the Latta one. That's where I took the pages from.

MR. SCHULTZ: Yeah, I think there is --

MS. CHRISTENSEN: Yes, please -- yeah, no, please pull up the Latta originally -- as originally filed.

MR. WAHLEN: I'm -- the original Latta testimony is not in the record. It was refiled as Chronister II. And so if she is going to ask questions about a piece of testimony that isn't in the record, it's going to get kind of confusing.

CHAIRMAN LA ROSA: Yeah, let's -- yeah, let's get clarification on that.

MS. CHRISTENSEN: The problem that I am

having, Commissioner, is that since Latta -- the original Latta as filed, which was adopted by Mr. Chronister before then, he subsequently added it as Chronister II, I just took page numbers for that.

So to sync up what testimony I am talking about Mr. Latta, it's easier to refer to the original version. I mean, we could try it with Chronister II, but it's going to -- my pages are going to be off, so I will do my best.

THE WITNESS: If it helps, Chronister II and Latta have the same page numbers, so I am okay.

MS. CHRISTENSEN: I don't think they do in the Case Center.

THE WITNESS: If she wants to refer to it that way, I can still, but I think --

MR. SCHULTZ: That's what we ran into last time --

CHAIRMAN LA ROSA: Yeah.

THE WITNESS: Right.

MR. SCHULTZ: -- when she called out 57, and I brought it up, it was not the right page when I looked at the two side-by-side in Case Center. I am not sure what happened, but they are not -- 57 is not the same on both.

THE WITNESS: I will try to follow along.

MS. CHRISTENSEN: The testimony will be the same. It's just the page numbers will be slightly off during -- from the two versions, unless there were changes in Mr. Latta's testimony, but they shouldn't be in the actual substance of the testimony.

THE WITNESS: No, there won't.

CHAIRMAN LA ROSA: Right. Okay. Let's try to move on.

MR. WAHLEN: I guess we will soldier on. We filed the Chronister II testimony on May 3rd. I am just struggling with why we are going to be asking about a different set of testimonies, but we will do the best we can. We want to get through this.

CHAIRMAN LA ROSA: Yeah, and I do as well, but I also want to get this right. So can we try to work off the Chronister II?

MS. CHRISTENSEN: We certainly can. I only have a few questions related to Mr. Latta's testimony in Chronister II. I just don't know how much the pages are off.

THE WITNESS: Sure.

MS. CHRISTENSEN: If I knew that, I could direct you at the correct thing.

CHAIRMAN LA ROSA: Yeah, let's take a shot at it and then --

THE WITNESS: Yeah, we can find it.

BY MS. CHRISTENSEN:

Q Okay. So in the original Mr. Latta's testimony, I have been looking at page 53 in his discussion about affiliate transactions. So if it's off by one or two in Chronister II --

A We are good.

Q -- we will get there.

A Is there a question on line 11?

Q I was looking at lines 24 and 25 of that testimony.

A Okay.

Q And on my -- if I could find way there the first time, I think we will be good.

And just for clarification, this is the Chronister II. Okay, thank you. Okay. I think we are good. Well, I will ask questions, and if we get lost, we will do our best.

A Sounds good.

Q Okay. Direct charges -- you would agree direct charges are when the affiliate is only receiving the product or the service from TECO, correct?

A Are you referring to something -- phraseology? I -- just to be helpful when you move things along, a direct charge is when the cost is associated with an activity that was only done for that affiliate. So the direct charge happens when that cost was incurred just for the product or service that went to that affiliate.

Q Okay. And I will accept that response.

A Okay.

Q And an assessed charge are determined and distributed using cost causative calculations based on certain metrics, such as headcount or square footage, correct?

A Correct. They can be called assessed or allocations.

Q And you would agree that some allocated costs are distributed in TECO using the Modified Massachusetts Method, using the total operating revenues, total operating assets, less cash and net income is the basis of the allocation, correct?

A Yes.

Q Okay. We would ask to have you look at OPC-169.

A It's on the screen now.

Q Okay. And this is a response regarding affiliate transactions. Do you see that?

A Yes, I do.

Q Okay. And the question that was being asked

here under Section A and Section B were regarding any analysis or study that shows the cost allocations to TECO are reasonable and consistent with market or benchmarks in the industry regarding affiliate transactions, correct?

A Yes.

Q Okay. And looking at the last paragraph under the answer A -- you may need to scroll down.

A Yes.

Q Okay. Other than identifying good business practices and periodic regulatory reviews, Emera and TECO have not performed any analysis or studies to show that costs allocated to TECO are reasonable or consistent with market or benchmarks, correct?

A That's not exactly how it reads. But to your point, what this answer is saying is that we have external auditors and internal auditors, and that all of the transactions are subject to those internal and external audits, and subject to all of the regulatory audits performed by the PSC staff.

Q Okay. So if I can, can you read out the last paragraph of paragraph A in this response?

A Sure. I am going to move the microphone so I can --

Q Certainly. Yeah.

A The combination of good business practices and periodic regulatory review give Tampa Electric confidence that the amounts charged and allocated to and from Tampa Electric and its affiliates, and the methods for making those charges and allocations are reasonable.

Q Can you read the last sentence?

A Sure.

Otherwise, Emera, TECO and affiliates have not performed analyses or studies as contemplated in the question --

Q Thank you.

A -- and raised in the question was benchmarking.

Q And market analysis?

A Yes, bench -- market or benchmarks in the industry.

Q Okay. Thank you.

A Yep.

Q Now let's look on your rebuttal testimony, starting at page 36. And I believe this is where you start discussing affiliate transactions in your rebuttal testimony?

A Yes.

Q Okay. And then it -- give me a second.

A Sure.

Q Okay. All right. It must be the end of the day. The machine is tired like me.

Okay. Now, if we scroll down that page and start looking at page 37, starting around line 14, there is a discussion regarding the amount of discovery that OPC served regarding just affiliate transactions. And you talk about that at least 100 discovery requests were propounded, including PODs, and including 275 subparts just on the affiliate transaction subject alone, correct?

A Yes. That's the volume of discovery that we responded to on affiliate transactions.

Q Okay. You would agree that that's a lot of information that had to be produced, and then also had to be reviewed by OPC's witness in a short two-month period of time, correct?

A No, I don't agree with that.

Q You don't agree it was a lot of information and that they have short period of time to review that information?

A Right. I don't agree with that. Let me explain why I don't agree.

MFR F-3 is -- it requires the company to submit the diversification pages from the Form 1 that we send annually to the Florida Public Service Commission, 35 pages in that diversification report that lays out all of the affiliate transactions --

Q I am going to object. This is non-responsive.

A Well, no, you asked if it was a short amount of time to look at the data. And the point that I am making is a lot of these interrogatories covered the data that we provided in the Form 1. We actually gave OPC 2020 through 2025 data.

MS. CHRISTENSEN: I'm going to renew my objection, it's non-responsive.

CHAIRMAN LA ROSA: Okay. So -- well, I think the witness has given a response. I think he is just -- he is giving the depth of why he said that he didn't agree.

MS. CHRISTENSEN: Well, I don't think he is actually responding to like two months in a short period of time.

BY MS. CHRISTENSEN:

Q When were the -- the MFRs were filed in -- April 2nd of 2024, correct?

A The MFR that had the 2023 diversifications was filed April 2nd, 2024.

Q And OPC's testimony was --

A -- and each of the diversification reports prior to that were filed in April of each year prior.

Q Right. And OPC's testimony was due to be filed June, I believe 6th, of 2024?

A And do agree with you that from April to June is a two-month period.

Q Okay. Thank you. I will move on.

Can I ask that you look at the other documentation that we passed out, and I believe that is the Nova Scotia --

A Is it OPC-238?

Q It may have that title. And it should be -- if you flip up the first page, it should say the NS Power Cost Allocation Manual. Do you see that?

A Yes, I do.

Q Okay. And on the bottom of page 40 of your rebuttal testimony -- okay. Looking at that, starting around line 24, this is where you start to discuss the use of the Nova Scotia Power Cost Allocation Manual, correct?

A That's correct.

Q And this is the Nova Scotia Power Cost Allocation Manual that you are referring to in your testimony?

A Yes, the exhibit you handed out is that.

Q Okay. Would you agree that in the Nova Scotia CAM, it's not -- that this is not specifically named or

mentioned as the Emera CAM, correct?

A I agree with you, in that it refers to the parent company. It doesn't use the work Emera.

Q Okay. Would you also agree that the Nova Scotia CAM does not specifically mention any type of affiliate transactions between Nova Scotia Power and TECO because there are not significant tran -- transaction -- or significant operation -- operating expenses transactions between the two, correct?

A I disagree with the last part on -- you mentioned because it was not a significant amount of transactions.

I agree with the first part, in that the word Tampa Electric doesn't appear. It uses the word affiliate.

Q Okay. To the extent that Nova Scotia Power CAM does not address affiliate transactions -- sorry, let me repeat the question.

To the extent Nova Scotia Power CAM does address affiliate transactions, it is document that lays out what the methods and techniques would be Nova Scotia Power cost allocation transactions with affiliates, correct?

A It has that and the parent company transaction rules as well.

Q Okay. And you would agree that the names Emera, TECO do not appear in the Nova Scotia Power CAM?
A Correct. They use the words parent and affiliate.
Q Okay. And there is a specific TECO CAM, the most recent one is effective January 1st, 2024, for transactions between TECO and its affiliates besides Emera, correct?
A Yes. We have had an affiliate transaction CAM at Tampa Electric for decades.
Q And you would agree, there is no Emera specific CAM, correct?
A Again, the rules associated with Emera charges are in this cost allocation manual you gave me.
Q Okay. Let me ask a question again. There is no actual Emera cost allocation manual, correct?
A There is not a cost allocation manual that has the title Emera.
Q Okay. And you agree that it is odd for a utility to have a parent utility -- or to not have a parent utility CAM, correct?
A No, I don't agree with that. The reason is that no Nova Scotia Power existed for decades before Emera was created, and so the utility review board in Nova Scotia would use a Nova Scotia Power CAM for all

affiliate transactions. When they created the company Emera, the parent company, then it was subsumed into the authority of the utility review board.

Q Right. But you would agree, you don't know of any other parent company that has affiliate transactions with its subsidiaries that does not have a specific CAM itself?

A I don't know any others, and we don't either --

Q Thank you.

A -- because we have it in here.

Q Looking at line 42 of your testimony, your rebuttal testimony to be specific. Starting at line 22, and then going over to line three on the next page, page 42, starting on line 22. You would agree, the most affiliate expenses are administrative or corporate expense -- or corporate services which are charged from Emera to TECO, or from TECO Electric to TECO, and are recorded in the A&G expenses on TECO's books, correct?

A You said TECO Electric to TECO -- I don't understand that part of it.

Q Okay. You have -- well, let me back this up.

Am I correct that TECO uses the 2025 budget amounts for affiliate charges in the revenue requirement in this case?

A Yes, the budgeted affiliate charges for '25 years are used in the test year.

Q Okay. And would you agree that most affiliate expenses are administrative or corporate services which are charged from Emera onto TECO, or from TECO Electric to TECO, and that those transactions are reported in A&G expense on TECO's books?

A I will try to answer your question with what I think you are looking for in that second half.

So the charges that come down from Emera, which, in 2023, were 15 million in the test year, they are 2.8 million below that number in the test year, they were around 12 million. Those charges usually recorded in an A&G expense account.

I think the other ones you were referring to was when Tampa Electric charges affiliates of Tampa Electric. And when we make those charges, I would say that the majority of them are in A&G expense accounts, but I am not responsible for our affiliates general ledgers and where they exactly book them when they get to their general ledger. But when they appear originally in ours, they are predominantly in the A&G accounts, yes.

Q Okay. And isn't it correct that TECO did provide budget documents which show the 2025 affiliate

expense amounts charged by TECO, by Emera and TECO Electric, and show the adjustments to each of the specific budgeted A&G accounts for these affiliate charges, or show the amount of affiliate expenses charged to each specific budgeted A&G account?

MR. WAHLEN: Can I interrupt? I don't know who TECO Electric is.

CHAIRMAN LA ROSA: Yeah. This is the second or third time there was that reference. I think the witness was confused on --

MS. CHRISTENSEN: No, I think we are talking about --

MR. WAHLEN: Is that Tampa Electric?

MS. CHRISTENSEN: -- Tampa Electric and TECO Energy. I think it's -- I will -- let me restructure that, because I think we are talking Tampa Electric and then its parent company, and then to Emera, its ultimate parent company.

THE WITNESS: Well, just be clear on that, Emera charges Tampa directly. That doesn't go through TECO Energy.

BY MS. CHRISTENSEN:

Q Okay. Then let me rephrase the question.

Did you provide any documents that show the 2025 budgeted affiliate expense amounts from Tampa

Electric charged from Emera, or TECO, the -- its Holding company parent?

A Yes, we did. In those 100 interrogatory and production of document requests we provided all of the spreadsheets for 2020 through 2025. So it included budget figures for all of the charges coming down from Emera, and all of the affiliate charges incurred by Tampa Electric and sent to other affiliates.

In addition to doing that, in PDF document form, we actually provided OPC with the live Excel files that showed all of the calculations, and allowed for drop-down menus to see it by cost type by company.

Q Okay. Let me ask you this: On page 39 of your testimony, starting at line --

A Of rebuttal?

Q I believe we are still in your rebuttal, yes.

A Okay.

Q Starting at line 12, I believe.

A Yes.

Q Okay. You discuss the FERC Form 1 pages in the diversification pages that you file with the Commission, correct?

A That's correct.

Q And then you talk about the Commission had the opportunity to review the information of FERC form, and

say that they can send data requests, right?

A Yes.

Q Okay. You are not claiming in your testimony here that just because TECO files the FERC Form 1 and the diversification data with the Commission every year, irrespective of whether the Commission follows up with data requests, that the Commission has formally approved affiliate transactions or does not have any concerns, correct?

A No, I am not claiming formal approval.

Q Okay. And you would agree that the specific information, such as charges -- or, sorry -- changes in allocation method from the prior year, that granular level of detail is not in diversification report, correct?

A Correct. The diversification report does not have the granular allocation calculations in it.

Q Okay. And it would be fair to say that you do not know the depth with which the Commission reviews this data every year, correct?

A I don't agree with that. Can you say it again?

Q Sure.

You just don't know how much or what the Commission does in its review of those diversification

forms every year, and the diversification pages every year?

A That's correct. I don't know what the Commission does with the forms.

Q All right. And looking at page 45 -- I think that's -- yeah, 45 -- page 45 of the rebuttal testimony, starting at line one.

Okay. You talk about Mr. Ostrander's recommendation to change the headcount in the Massachusetts model from net -- the net income factor that TECO currently uses, correct?

A That's what I talk about there, yes.

Q And you would agree that TECO substantially relies on headcount to allocate some of the affiliate cost, correct?

A Can you repeat that question?

Q Sure.

You use headcount as a methodology to allocate cost to -- as one of those, I think, cost causative allocation methodologies?

A We have 11 different allocation or assessment methodologies, and headcount is one of those, yes.

Q Okay.

CHAIRMAN LA ROSA: Ms. Christensen, this question isn't intended to rush you by any means,

but how many more questions do you think you have for this witness? And it's -- any answer is okay.

MS. CHRISTENSEN: Oh, I am just -- I am looking to see if there is any further questions. Give me a few minutes. If I can have a five-minute break, I may be ready to wrap up.

CHAIRMAN LA ROSA: Yeah, and that's all right. That's where I am leaning too. So let's do that. Let's have a 10-minute break, intention to come in right back at five o'clock.

(Brief recess.)

(Transcript continues in sequence in Volume 16.)

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 videotaped 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 6th day of October, 2024.

DEBRA R. KRICK
NOTARY PUBLIC
COMMISSION #HH575054
EXPIRES AUGUST 13, 2028.