COMMISSIONERS:
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STATE OF FLORIDA

OFFICE OF COMMISSION CLERK
ADAM J. TEITZMAN
COMMISSION CLERK
(850) 413-6770

Public Service Commission

March 5, 2025

John A. Tomasino, Clerk
Florida Supreme Court
500 South Duval Street
Tallahassee, Florida 32399

Re: Petition for Rate Increase by Tampa Electric Company 20240026-EI

Dear Mr. Tomasino:

Enclosed please find a certified copy of a Notice of Administrative Appeal, which was filed with the Public Service Commission on 03/03/2025, along with its attachment, Order No. PSC-2025-0038-FOF-EI. This appeal was filed on behalf of the Office of Public Counsel.

Please do not hesitate to contact me should you have any questions concerning this matter.

Sincerely,

Adam J. Teitzman
Commission Clerk

AJT: bms
Enclosure

cc: B. Marshall
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Samantha Cibula
Adria Harper
Timothy Sparks
Carlos Marquez

<table>
<tr><td>CITIZENS OF THE STATE OF FLORIDA, THROUGH THE FLORIDA OFFICE OF PUBLIC COUNSEL,

Appellants,

v.

FLORIDA PUBLIC SERVICE COMMISSION

Appellee.</td><td>)
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DOCKET NOS. 20240026-EI
20230139-EI
20230090-EI

NOTICE OF ADMINISTRATIVE APPEAL</td></tr>
</table>

NOTICE IS GIVEN that the Citizens of the State of Florida ("Citizens"), Appellants, through the Office of Public Counsel, appeal to the Supreme Court of the State of Florida the order of the Florida Public Service Commission, Order No. PSC-2025-0038-FOF-EI, rendered on February 3, 2025. A copy of Order No. PSC-2025-0038-FOF-EI is attached to this Notice of Administrative Appeal as Exhibit "A."

The nature of the order is that it is the Final Order Granting in Part and Denying in Part Tampa Electric Company's Petition for Rate Increase.

Pursuant to Fla. R. App. P. 9.110(d), Citizens hereby inform the Court that Citizens filed a Motion for Reconsideration and Motion for Clarification of Certain Provisions of Order No. PSC-2025-0038-FOF-EI with the Florida Public Service Commission on February 18, 2025, and that motion is pending.

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Attorney for Citizens of the State of Florida

CERTIFICATE OF SERVICE

DOCKET NO. 20240026-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 3rd day of March, 2025, to the following:

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CERTIFICATE OF COMPLIANCE

I HEREBY certify that the foregoing is typed in Bookman Old Style 14-point font and therefore complies with the font requirements of Rule 9.045, Florida Rules of Appellate Procedure.

/s/ Patricia A. Christensen
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CITIZENS OF THE STATE OF FLORIDA, THROUGH THE FLORIDA OFFICE OF PUBLIC COUNSEL,	)	**IN THE FLORIDA PUBLIC SERVICE COMMISSION**
Appellants,	)	**DOCKET NOS. 20240026-EI 20230139-EI 20230090-EI**
v.	)	
FLORIDA PUBLIC SERVICE COMMISSION	)	**NOTICE OF ADMINISTRATIVE APPEAL**
Appellee.	)	

EXHIBIT "A"

FLORIDA PUBLIC SERVICE COMMISSION

ORDER NO. PSC-2025-0038-FOF-EI

ISSUED FEBRUARY 3, 2025

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Tampa Electric Company.	DOCKET NO. 20240026-EI
In re: Petition for approval of 2023 depreciation and dismantlement study, by Tampa Electric Company.	DOCKET NO. 20230139-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.	DOCKET NO. 20230090-EI ORDER NO. PSC-2025-0038-FOF-EI ISSUED: February 3, 2025

The following Commissioners participated in the disposition of this matter:

MIKE LA ROSA, Chairman
ART GRAHAM
GARY F. CLARK
ANDREW GILES FAY
GABRIELLA PASSIDOMO SMITH

FINAL ORDER GRANTING IN PART AND DENYING IN PART TAMPA ELECTRIC COMPANY'S PETITION FOR RATE INCREASE

APPEARANCES:

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Advisor to the Florida Public Service Commission.

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Florida Public Service Commission General Counsel

Table of Contents

List of Acronyms

AFUDC	Allowance for Funds Used During Construction
AD	Average Demand
ADIT	Accumulated Deferred Income Taxes
AMI	Advanced Metering Infrastructure
AMR	Advanced Meter Reading
AOM	Asset Optimization Mechanism
ARL	Average Remaining Life
ASL	Average Service Life
BB4	Big Bend Unit 4
BCA	Benefit-Cost Analysis
BEBR	Florida's Bureau of Economic and Business Research
BESE	Battery Energy Storage Equipment
BOC	Bearss Operations Center
CAM	Cost Allocation Manual
CAPM	Capital Asset Pricing Model
CATS	Consumer Activity Tracking System
CC	Combined Cycle
CCS	Carbon Capture and Storage
CDD	Cooling Degree Days
CETM	Clean Energy Transition Mechanism
CIAC	Contributions in Aid of Construction
CIP	Critical Infrastructure Protection
Commission	Florida Public Service Commission
CP	Coincident Peak
CPI	Consumer Price Index
CPVRR	Cumulative Present Value of Revenue Requirements
CSP	Centralized Service Provider
CT	Combustion Turbine
CWIP	Construction Work in Progress
D&O	Directors and Officer
DAP	Data Analytics Platform
DC	Direct-Current
DCF	Discounted Cash Flow
DEF	Duke Energy Florida, LLC
DER	Distributed Energy Resources
DPS	Dividends per Share
ECAPM	Empirical Capital Asset Pricing Model
ECC	Energy Control Center
ECCR	Energy Conservation Cost Recovery Clause
ECRC	Environmental Cost Recovery Clause
EDITs	Excess Deferred Income Taxes
EDR	Economic Development Rider

EMS	Energy Management System
EPS	Earnings per Share
ERP	Enterprise Resource Planning
EUSHI	Emera United States Holdings, Inc.
F.A.C.	Florida Administrative Code
F.S.	Florida Statutes
FCTC	Florida Conservation and Technology Center
FEA	Federal Executive Agencies
FEECA	Florida Energy and Efficiency Conservation Act
FERC	Federal Energy Regulatory Commission
FIPUG	Florida Industrial Power Users Group
FL Rising	Florida Rising, Inc.
FPL	Florida Power & Light
FPSC	Florida Public Service Commission
FPUC	Florida Public Utilities Company
FRF	Florida Retail Federation
Fuel Retailers	Americans for Affordable Clean Energy, Inc.; Circle K Stores, Inc.; RaceTrac Inc.; and Wawa, Inc.
GAAP	Generally Accepted Accounting Principles
GBRA	Generation Base Rate Adjustment
GDP	Gross Domestic Product
GRR	Grid Reliability and Resilience
GS	General Service – Non-Demand
GSD	General Service - Demand
GSLDPR	General Service Large Demand – Primary
GSLDSU	General Service Large Demand - Subtransmission
HDD	Heating Degree Days
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
IOU	Investor-Owned Utilities
IRA	Inflation Reduction Act of 2022
IRC or Code	Internal Revenue Code
IRS	Internal Revenue Service
IT	Information Technology
ITC	Investment Tax Credits
kW	Kilowatt
kWh	Kilowatt Hour
LDES	Long Duration Energy Storage
LNG	Liquid Natural Gas
LS	Lightning Service
LTIP	Long Term Incentive Plan
LULAC	League of United Latin American Citizens of Florida
MFR	Minimum Filing Requirements
MMM	Modified Massachusetts Model
Moody's	Moody's Analytics

MRP	Market Equity Risk Premium
MW	Megawatt
MWh	Megawatt hour
NARUC	National Association of Regulatory Commissioners
NERC	North American Electric Reliability Corporation
NOI	Net Operating Income
NPVRR	Net Present Value Revenue Requirement
NS	Net Salvage Percentage
NSMR	Non-Standard Meter Rider
O&M	Operational and Maintenance
OPC	Office of Public Counsel
OPEB	Other Post-Retirement Employee Benefit
PDA	Parent Debt Adjustment
PLTE	Private Cellular Network
PRPM	Predictive Risk Premium Model
PTC	Production Tax Credits
R&D	Research and Development
RAP	Regulatory Assistance Project
REC	Renewable Energy Credit
RICE	Reciprocating Internal Combustion Engines
ROE	Return on Common Equity
RPM	Risk Premium Models
RS	Residential Service
SAE	Statistically Adjusted End-use
SERP	Supplemental Executive Retirement Plan
SoBRA	Solar Base Rate Adjustment
SPR	Simulated Plant Record
SPPCRC	Storm Protection Plan Cost Recovery Clause
SSD	Sum of Squared Differences
ST	Steam Turbine
STR Project	South Tampa Resilience Project
SYA	Subsequent Year Adjustment
TECO or Company	Tampa Electric Company
TMARPM	Total Market Approach RPM
TOTI	Taxes Other than Income Taxes
WACC	Weighted Average Cost Of Capital
Walmart	Walmart, Inc.
WMS	Work Management System

BY THE COMMISSION:

Case Background

On April 2, 2024, Tampa Electric Company (TECO or Company) filed its Petition for Rate Increase (Petition), minimum filing requirements (MFRs), and testimony.[1] TECO provides service to approximately 844,000 customers in a 2,000 square mile service territory in Hillsborough and portions of Polk, Pasco, and Pinellas counties, Florida.

TECO initially requested an increase of approximately $296.6 million in base rates and charges effective January 1, 2025. In addition, the Company requested incremental rate increases of approximately $100 million, effective January 1, 2026, and $72 million, effective January 1, 2027. On August 22, 2024, the Company reduced its initial request for rates in 2025 to $287.9 million, with the incremental rate increases also reduced to $92.4 million and $65.5 million, for 2026 and 2027, respectively.[2] TECO requested a return on common equity (ROE) of 11.5 percent.

TECO's last base rate hearing was in 2021. In that proceeding the Florida Public Service Commission (Commission or FPSC) approved a unanimous settlement agreement (2021 Settlement Agreement) which authorized a total base rate increase of $123 million in 2022; a $90 million generation base rate adjustment (GBRA) in 2023; and a $21 million GBRA in 2024.[3] The GBRAs were designed to recover the costs associated with the completion of the Big Bend modernization project and additional solar facilities. TECO's authorized ROE was initially established at 9.95 percent. Due to the increase in interest rates, the ROE trigger provision of the 2021 Settlement Agreement reset TECO's ROE to the current level of 10.2 percent.

The Office of Public Counsel's (OPC) intervention in this matter was acknowledged by Order No. PSC-2024-0048-PCO-EI, issued February 26, 2024. On April 23, 2024, intervention was granted to Federal Executive Agencies (FEA); Sierra Club; Florida Rising, Inc. (FL Rising); League of United Latin American Citizens of Florida (LULAC); Florida Retail Federation (FRF); and Florida Industrial Power Users Group (FIPUG).[4] On June 3, 2024, intervention was granted to Americans for Affordable Clean Energy, Inc.; Circle K Stores, Inc.; RaceTrac Inc.; and Wawa, Inc. (Fuel Retailers).[5] Intervention was granted to Walmart, Inc. (Walmart) on August 8, 2024, by Order No. PSC-2024-0317-PCO-EI.

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[1] By Order No. PSC-2024-0096-PCO-EI, Docket Nos. 20240026-EI, 20230139-EI, and 20230090-EI were consolidated.
[2] Document No. 08609-2024.
[3] Order No. PSC-2021-0423-S-EI, issued Nov. 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*
[4] Order Nos. PSC-2024-0121-PCO-EI, PSC-2024-0122-PCO-EI, PSC-2024-0123-PCO-EI, PSC-2024-0124-PCO-EI, and PSC-2024-0125-PCO-EI.
[5] Order No. PSC-2024-00182-PCO-EI.

Two virtual customer service hearings were held on June 10 and 11, 2024, and one in-person service hearing was held in Tampa on June 13, 2024. A total of 53 customers testified. An administrative evidentiary hearing was held August 26-30, 2024.

This Order addresses the requested rate increases for 2025, 2026, and 2027. The Commission has jurisdiction over this matter pursuant to Chapter 366, including Sections 366.06 and 366.076, Florida Statutes (F.S.). Some issues were entirely or substantially uncontested, with little to no argument presented by some or all intervening parties, and our more limited analysis on these subjects reflects that. Other issues, such as the Return on Equity, were vigorously debated by multiple expert witnesses representing a broad range of interests and our more extensive analysis reflects that as well.

Decision

I. Preliminary Matters

A. Motions for Official Recognition

On August 9, 2024, OPC filed a Motion and Notice of Intent to Seek Official Recognition of customer comments and customer complaints.[6] On August 20, 2024, TECO filed a Response to OPC's Motion and Notice of Intent to Seek Official Recognition and Request for Official Recognition of excerpts from our consumer affairs reports.[7] During the hearing, both movants indicated they would not object to the entry of the other's documents into evidence. Having entered those three exhibits into evidence upon agreement of the parties, we find this resolution has rendered the motions moot and therefore dismiss them.

B. Joint Motion for Stipulation

On August 22, 2024, a Joint Motion for Approval of Stipulation was submitted by FL Rising/LULAC and FRF.[8] In lieu of cross-examining FRF witness Chriss, the movants requested we accept the following factual stipulations regarding his testimony: (1) Although witness Chriss testified that FRF does not oppose the 4CP and MDS cost of service methodology, witness Chriss did not testify that FRF supports that methodology; (2) witness Chriss did not conduct his own cost-of-service study for this case; (3) witness Chriss did not evaluate the energy value versus the capacity value of the solar power plants that TECO is adding to its grid; and (4) witness Chriss did not evaluate how much of TECO's generation investments are comprised of solar.

Having heard no objection from any party at the hearing, we accept these factual stipulations and enter them into the record finding these further the administrative and judicial economy of our hearing.

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[6] Document No. 08355-2024, filed Aug. 9, 2024, in Docket No. 20240026-EI.
[7] Document No. 08543-2024, filed Aug. 20, 2024, in Docket No. 20240026-EI.
[8] Document No. 08602-2024, filed Aug. 22, 2024, in Docket No. 20240026-EI.

II. Test Period and Forecasting

Here we address three issues that relate to the projected test period and the associated forecasting of customers, energy, and demand. These issues were identified as Issues 1-3 in the Prehearing Order issued August 14, 2024, Order No. PSC-2024-0351-PHO-EI, and specifically relate to the selection of the projected test year (Issue 1), a largely uncontested issue, as well as the methodology for forecasting test year customers, energy (kilowatt hours) and demand (kilowatts) (Issue 2). Also we address the selection and application of certain forecasting trend factors, such as customer growth rates and inflation (Issue 3).

A. Projected Test Year (Issue 1)

1. Analysis

In general, a projected test year methodology uses forecasted data for a 12-month period to match average revenues and expenses with average rate base investment. TECO's projected test period comprised the 12 months ending December 31, 2025. TECO witness Chronister maintained the projected test period "reflects the Company's projected revenues and expenses, capital structure, and rate base required to provide safe, reliable, and cost-effective service to customers when the Company's proposed new rates for 2025 will be in effect." TECO alleges this issue is uncontested. OPC, FL Rising/LULAC, and FIPUG agreed that the 2025 test year is appropriate "with adjustments" while FRF and Walmart stated that the use of a projected test year is consistent with Commission practice.

2. Conclusion

No intervenors offered any specific adjustments to be made to the test year, and we agree with the Company that this issue appears uncontested. We also agree that the 12 months ending December 31, 2025, provides a reasonable and forward-looking basis for assessing TECO's financial and operational performance and allows for a thorough evaluation of future revenues, expenses, and rate base investment. Further, we find this test period ensures that the projections reflect current trends and anticipated developments and future conditions making it a sound period for regulatory and financial planning and is consistent with our prior practice and policy.

TECO's proposed 2025 test year will result in a matching of the Company's projected revenues with average rate base investment and average expenses during the first 12 months in which the new rates would be in effect. No testimony was provided in this case to the contrary, therefore, we find that the projected test period of the 12 months ending December 31, 2025, is appropriate.

B. Customer, Energy, and Demand Forecasts (Issue 2)

1. Analysis

An electric utility's load forecast is a projection of the quantity of customers, energy, and demand over a specified period in the future. The load forecast helps a utility plan its energy production and manage resources to ensure reliable service for customers. Typically, a utility's load forecast is the composite of revenue and rate class forecasts. The Company's customer, use-per-customer (energy), and demand forecasts in this proceeding were sponsored by TECO witness Cifuentes and utilized an integration of econometric models and Statistically Adjusted End-use (SAE) models to develop the Company's load forecast for the 2025 test year.

a. TECO's Customer Forecast

TECO witness Cifuentes stated that the primary economic drivers for its customer forecast are Hillsborough County population estimates, Hillsborough County Commercial and Manufacturing employment statistics, building permits, and time-trend variables. With this information, according to witness Cifuentes, TECO developed a forecasted annual customer growth rate of 1.7 percent for the 2025 test year, resulting in a forecast of 862,443 customers. OPC witness Dismukes remarked that TECO's forecasts of customers historically have been understated, ranging from -0.3 percent to -2.2 percent per year, however OPC did not directly challenge TECO's customer forecast itself nor the inputs used to arrive at the Company's forecast. FRF also criticized TECO's customer forecast as being understated, while FIPUG and Walmart adopted OPC's position.

We have reviewed TECOs customer models, assumptions, and inputs used to project the Company's number of customers for the 2025 test year. TECO's 0-3 year average error rate with respect to its customer forecast was -0.5 percent, while its projection of 1.7 percent growth is comparable to its historical customer growth average over the past 15 years (1.6 percent). We are persuaded by witness Cifuentes' testimony, and we find the Company's customer forecast of 862,443 for the 2025 test year is reasonable.

b. TECO's Energy Sales Forecast

TECO's energy sales forecast is essentially the result of multiplying the utility's customer forecast by its use-per-customer consumption forecast. A use-per-customer forecast predicts how much energy each customer (such as a household, business, or factory) will likely use on average. Factors such as energy efficiency improvements, new technologies (electric vehicles, solar, etc.), and seasonal variations in demand can impact a utility's use-per-customer forecast. TECO projects its total use-per-customer energy consumption to decline by approximately 3.9 percent from 24,925 kWh in 2023 to 23,949 kWh in 2024, and then decline by another 0.9 percent from 23,949 kWh in 2024 to 23,730 kWh for the 2025 test year. To explain the forecasted reduction, TECO cited improvements in end-use efficiency resulting from appliance and equipment replacement; new end-use standards, such as new lighting standards, economyinduced conservation; demand-side management (DSM) program activity; and the continued addition of rooftop solar panels.

After multiplying its use-per-customer forecast by its customer forecast for the 2024 historic base year + 1 and the 2025 test year, TECO projects its total retail energy sales to decline by approximately 2.3 percent, from 20,791 gigawatt hours (GWh) in 2023 to 20,315 GWh in 2024, and then increase by 0.7 percent from 20,315 GWh in 2024 to 20,466 GWh for the 2025 test year. TECO witness Cifuentes explained that the primary cause of the decline in its forecasted 2024 energy sales is due to "higher energy consumption in 2023 due to hotter weather versus a projection of energy consumption for 2024 under normal weather conditions." Witness Cifuentes further explained that TECO's projected gradual increase in energy sales over the forecast horizon (2024–2033), including the 2025 test year, is due to customer growth, which is offset by its projected decline in energy use-per-customer.

An out-of-model adjustment is a manual adjustment made to the results of a model to account for factors not captured within the model itself. TECO's energy sales forecast incorporates three major out-of-model adjustments: energy efficiency, electric vehicle charging, and private rooftop solar. These three out-of-model adjustments collectively reduce the Company's energy sales forecast for the 2025 test year by approximately 168,429 megawatt-hour.

OPC witness Dismukes argued that TECO's forecasting methodology "fails to conform to historic trends and is biased" due to TECO's usage of out-of-model adjustments. Witness Dismukes argued that TECO's out of model adjustment calculations lack supporting evidence and rely on assumptions not supported by the record. OPC argued that TECO has a history of under-forecasting energy sales and concluded that we should address TECO's history of forecasting deficiencies by rejecting the Company's out-of-model adjustments, which would result in a 2025 sales projection of 20,635,457 megawatt-hours.

In rebuttal, TECO witness Cifuentes argued against OPC's suggested removal of the Company's out of model adjustments to its future energy sales projections. The Company contended that its forecasting models do not contain explanatory variables that capture the effects of conservation, electric vehicle charging, and customer-owned rooftop solar, and the removal of such adjustments would "impair the company's ability to provide reliable service to its customers and would impede Tampa Electric's ability to plan appropriately for future generation and infrastructure needs."

OPC witness Dismukes' assertion that TECO's out-of-model adjustments lack supporting evidence and proper documentation is inaccurate, and we find the Company's out-of-model adjustments are substantiated and well-documented as detailed in the rebuttal exhibits of witness Cifuentes. We also find the adjustments are appropriate to account for the impacts of new technologies and other needs as argued by TECO witness Cifuentes. Therefore, we disagree with OPC's proposed removal of the Company's out-of-model adjustments from its energy sales forecast.

Weather plays a vital component in a utility's load forecasts due to its direct and sizable impact on how much energy customers use. When modeling use-per-customer, utilities rely on an assumption of "normal weather" which is a utility-calculated baseline used to estimate typical weather conditions over a specific period. This modelled weather is then used as the utility's projected weather in the test year used to create the Company's sales and demand forecasts. TECO obtained its weather data from a National Oceanic and Atmospheric Administration (NOAA) weather station located at Tampa International Airport, which represents the weather conditions in TECO's service area. TECO's normal weather projection acts as a baseline for its weather variables, measured in cooling degree days (CDD) and heating degree days (HDD), which are the leading driver in TECO's energy sales.

TECO utilized Monte Carlo simulations over a 20-year historical base period to calculate normal weather conditions. TECO witness Cifuentes explained that the Company utilized the 50th percentile in their Monte Carlo simulations when calculating normal weather which results in CDD and HDD projections being very similar to a straight average over the past 20 years. TECO witness Cifuentes maintained that a 20-year historical base period provides a "stable" transition year-to-year in normal weather assumptions and is an important component for the Company's long-term planning.

OPC and FL Rising/LULAC argued against TECO's reliance on a 20-year weather normalization period for forecasting normal weather, claiming it "biases" results. OPC argued that the Company's energy sales forecasts "always understate results when compared to actuals but not always understate results when compared to weather normal actuals" suggesting that the Company's weather normalization adjustment is understating forecast results. Additionally, FL Rising/LULAC argues energy sales growth assumptions should instead assume that the Tampa area is experiencing increasing heat from climate change that will continue to get worse.

While TECO acknowledged that transitioning to a 10-year historic base period for calculating normal weather would increase projected sales for the test year, it also stated that the transition would "accelerate the need to build new generating plant and increase projected expense levels." TECO further argued that if it was forced to adopt a different period than 20-years, it would "impair the comparability" of Florida Reliability Coordinating Council (FRCC) data, which relies on a uniform period of 20-years for member utilities. TECO contended that its 2025 customer, demand, and energy forecasts use "theoretically and statistically sound" methods previously approved by this Commission which should be approved in this case. TECOs argument is more persuasive and we find that utilizing a normal weather forecast based on a 20-year historical average adequately accounts for the weather trends expected to be experienced by TECO in the near future.We find the Company's forecasts are well supported, reflect normal weather, and include appropriate adjustments to account for the impact of new technologies and energy conservation. On this basis, we find TECO's test year energy forecasts to be reasonable.

c. TECO's Demand Forecasts

A demand forecast is a measure of energy that consumers need or use at any given time, spiking during "peak" demand periods, i.e. summer and winter. Accurate demand forecasts are important for utilities in order to balance their resources, plan for future capacity, and inform how much energy is needed to produce, purchase, and/or store to maintain a reliable and efficient power supply for customers.

TECO forecasts peak demand on the per-customer basis, and multiplies that forecast by its customer forecast to arrive at its summer and winter peak forecasts for the test year. TECO explained that, given the increase in customers is offset somewhat by the effect of the forecasted reduction in energy-use-per customer, it projects a 1.2 percent increase in winter peak demand and a 0.8 percent increase in summer peak demand, resulting in a winter peak projection of 4,566 MW and a summer peak projection of 4,421 MW for the 2025 test year. No intervenors challenged TECO's demand forecasts, and we find no adjustments are necessary to the Company's proposed test year peak demand forecasts.

2. Conclusion

Based on the above analysis, we find that TECO's forecast of customers, energy sales (as measured in kWh), and demand (as measured in kW) are reasonable and are hereby approved.

C. Forecasting Trend Factors (Issue 3)

1. Analysis

Trend factors are numeric escalators (or multipliers) that are applied to historic expenses as an operational and maintenance (O&M) benchmarking tool and for preparing the forward-looking test year O&M expense budget amounts. Here we address TECO's application of inflation, customer growth, as well as labor and non-labor trend factors for the 2025 forecasted test year budget.

a. Inflation Trend Factor

TECO used the “Consumer Price Index (CPI) - All Items (unadjusted)” as its measure of inflation. The Company used CPI in its compound multiplier calculations as a comparative evaluation of its expense forecasts. The source of the CPI values that TECO used was the May 2023 forecast delivery provided by Moody’s Analytics (Moody’s), which estimated inflation values of 2.6 percent for 2024, and 2.1 percent for 2025. TECO stated it did not consider any alternative sources of CPI other than Moody’s, although it acknowledged that an internal work unit (Load Research & Forecasting) publishes an annual inflation forecast memo with CPI information for benchmarking purposes. For consistency across all schedules related to forecasting, the Company used the same source and forecasted values in all schedules in this proceeding that were related to CPI. TECO argued the forecasted inflation rate of 2.1 percent or the 2025 test year, which it obtained from Moody's, is reasonable and should be approved. No other party offered testimony on the inflation trend factors that TECO used for forecasting its 2025 test year budget.

Although TECO did not consider any alternative sources of CPI other than Moody's, the Company monitors CPI on a continuous basis through internal sources. We note the CPI values TECO sourced from Moody's May 2023 forecast delivery (inflation values of 2.6 percent for 2024, and 2.1 percent for 2025), which it used in this case, appear conservative when compared to Moody's May 2024 forecast. We also note that the CPI inflation value TECO used for its 2025 test year budget (2.1 percent for 2025) is nearly the same as the value that FL Rising/LULAC argued is appropriate (approximately 2 percent). For preparing the 2025 test year budget, we find that TECO's forecasted inflation rates of 2.6 percent (for 2024) and 2.1 percent (for 2025) are reasonable.

b. Customer Growth Trend Factor

A customer growth trend factor is a composite of elements that influence the rate at which a customer base expands over time. MFR Schedule C-33 reflects that TECO estimates customer growth at 1.69 percent for 2024, and 1.67 percent for 2025. In its analysis, TECO utilized the Bureau of Economic and Business Research and Moody's as sources for its input variables. TECO witness Cifuentes stated the primary economic drivers for customer forecasts are population estimates as well as employment, building permits, and time-trend variables based on the University of Florida's Bureau of Economic and Business Research (BEBR).

According to witness Cifuentes, TECO tested the reasonableness of its forecasts and assumptions by first comparing the projections to observed historical data. TECO additionally evaluates state and federal government resources, and also data from the University of Central Florida, as alternative sources of information for comparative purposes. The witness conceded that projections from the different sources vary slightly, but are consistent with regard to projecting the economic rebound forecasted for 2025. TECO argued the forecast of customer growth (1.7 percent) it used for forecasting the 2025 test year budget is an appropriate value.

OPC witness Dismukes did not offer alternatives to the inflation and customer growth trend factors TECO utilized for this proceeding, and no other party offered testimony specific to the customer growth trend factors that TECO used for forecasting its 2025 test year budget. However, FL Rising/LULAC argued in its post-hearing brief that TECO's 2025 test year customer growth forecasts should include the following Hillsborough County data: population estimates, commercial and manufacturing employment data, information on the number of building permits, and estimates on time-trend variables, such as customer growth values of about 1 percent per year, on a prospective basis.

The University of Florida's BEBR provides publicly available population data that TECO used as an input for its test year customer forecasting. In addition, the forecast data the utility receives from Moody's, including economic growth data, is extracted from a customized database that provides county-specific (Hillsborough) data. Additionally, TECO did incorporate Hillsborough County population and employment estimates to develop its customer forecasts as advocated for by FL Rising/LULAC, and supplemented that with other information from Moody's when developing its 2025 customer growth estimate of 1.7 percent. TECO's projection of 1.7 percent customer growth is comparable to its historical customer growth average over the past 15 years (which is 1.6 percent). Therefore, for preparing the 2025 test year budget, we find it is reasonable that TECO forecasted a customer growth rates of 1.69 percent (for 2024) and 1.67 percent (for 2025).

c. Labor Trend Factors

Labor trend factors are closely related to the compensation and payroll-related matters that are addressed later in this Order in the discussion of Issue 53. In its brief, TECO asserted that its 2025 budget forecast was prepared using a 3.75 percent increase for non-union labor and a 3.5 percent increase for union labor. TECO compared historic and forecasted (2021-2025) payroll and fringe benefits growth rates to the CPI. TECO witness Cacciatore stated Tampa Electric's 2025 budgeted gross average salary per active team member increased 7.6% since 2021 to $116,217, an average growth rate of 2 percent per year which is consistent with the average actual and forecasted CPI included in MFR Schedule C-35 for the period from 2021-2025.

TECO witness Cacciatore also stated that approximately 840 of its employees are part of a collective bargaining unit affiliated with two unions, and that TECO was engaged in negotiation activities for both agreements during 2024, although in 2023 the salary increases in their prior agreements were in the range of 3.0 to 3.5 percent. Witness Cacciatore also stated TECO's 2024 and 2025 forecasted labor costs are based on market survey data. The intervenors offered no testimony on the labor trend factors that TECO used for forecasting its 2025 test year budget.

2. Conclusion

Based on historical and projected gross average salary growth rates and CPI, as well as recently negotiated salary agreement increases, we find TECO's union and non-union labor trend factors are reasonable. We also find that TECO's forecasted inflation rates of 2.6 percent (for 2024) and 2.1 percent (for 2025) are reasonable, as well as the forecasted a customer growth rates of 1.69 percent (for 2024) and 1.67 percent (for 2025). The trend factors that should be used in forecasting the test year budget are: 2.1 percent for inflation, 1.7 percent for customer growth, 3.75 percent for non-union labor, and 3.5 percent for union labor.

III. Quality of Service

This section addresses the quality of service provided by TECO and whether it is adequate pursuant to section 366.041, F.S., which authorizes this Commission to consider the efficiency, sufficiency, and adequacy of the facilities provided and services rendered by the Company. This issue was identified as Issue 4 in the Prehearing Order.

A. Quality of Service (Issue 4)

1. Analysis

Pursuant to Section 366.041, F.S., in fixing rates we are authorized to give consideration, among other things, to the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered. This Commission held one in-person service hearing within TECO's service territory on June 13, 2024. Additionally, we held two virtual service hearings on June 10, 2024, and June 11, 2024. The service hearings provided an opportunity for customers to raise concerns regarding the Company's quality of service and its Petition. A total of 53 customers testified at the service hearings. Of those 53 customers, 44 customers expressed disapproval of a rate increase, and 9 customers expressed concerns with quality of service and reliability. The latter nine customers raised concerns regarding difficulty reaching customer service, billing issues, meter difficulties, excess vegetation, switchgear problems, pole replacement difficulties, and momentary power interruptions. TECO serves approximately 844,000 customers.

Commission staff witness Calhoun testified that, from April 1, 2020, through March 31, 2024, a total of 1,026 complaints were logged in the Commission's Consumer Activity Tracking System (CATS) and, of those complaints, 615 were transferred directly to TECO via the Commission's Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to TECO's customer service personnel for resolution. Of the 1,026 complaints, approximately 52 percent concerned billing issues and approximately 48 percent involved quality of service issues. Additionally, witness Calhoun testified that of the total 1,026 logged complaints, two quality of service and two billing complaints appeared to demonstrate a Commission Rule violation. For the two quality of service complaints, it appears that TECO did not provide a timely response to the Commission regarding those complaints. For the two billing complaints, the rule violation was associated with improper bills. Given that only four potential rule violations were identified by staff witness Calhoun with respect to logged CATS complaints, we find that TECO has demonstrated the ability to efficiently respond to customers.

TECO witness Sparkman argued that overall customer satisfaction has increased for both its residential and business customers, and exceeded the industry average in the utility benchmarking study conducted by J.D. Power. Witness Sparkman also explained that TECO focuses on six pillars for customer satisfaction: power quality and reliability, billing and payment, price, corporate citizenship, communication, and customer care. Witness Sparkman provided escalation totals, which consist of both customer complaints and inquiries, for the period of 2021 through 2023. Overall, it appears that the escalations received by both TECO and this Commission have increased each year for this period, however, it also appears the highest number of combined (TECO and Commission) escalations was 680 in 2023, which would represent approximately just 0.08 percent of TECO's total customer base.

While OPC did not file testimony on quality of service, it did offer two exhibits and argued we should keep in mind the testimony provided by TECO's customers. The first exhibit contained copies of approximately 900 customer comments filed in this docket. An overwhelming majority of comments, approximately 99 percent, expressed concerns over a potential rate increase. The second exhibit contained the customer complaints logged in CATS between January 1, 2022, and July 17, 2024. As discussed above, witness Calhoun's testimony identified CATS complaints logged between April 1, 2020, and March 31, 2024. The second exhibit showed an additional 28 complaints filed between April 1 and July 17, 2024, all of which appeared to be billing complaints with no apparent rule violations.

2. Conclusion

None of the intervenors offered testimony directly addressing quality of service. OPC argued that the Commission should consider the customer testimony from the service hearings as well as all of the customer complaints. The overwhelming majority of the customer testimony and comments addressed concerns with a potential rate increase rather than the quality of TECO's service. Given this as well as the fact that only four potential rule violations were identified from April 1, 2020, through July 17, 2024, we find TECO's quality of service is adequate.

IV. Depreciation and Dismantlement

This section addresses the Company's calculation of depreciation parameters and rates for TECO's depreciable plant accounts as well as the Company's provisions for estimated future dismantlement costs. These issues were identified as numbers 5 through 12 in the Prehearing Order. Specifically, here we determine the need to revise the Depreciation Rates and Dismantlement Provision (Issue 5) as well as the corresponding Implementation Date (Issue 6, an uncontested issue). Additionally, we determine the appropriate Depreciation Parameters and Rates (Issue 7), the theoretical reserve imbalances that result from any changes (Issue 8), and what measures should be taken to correct those imbalances (Issue 9). We also determine the treatment for Investment Tax Credits and the Flow Back of Excess Deferred Income Taxes (Issue 10), the Annual Accrual for Dismantlement (Issue 11), and the corrective measures for the Dismantlement Reserve (Issues 12).

A. Revision of Depreciation Rates and Dismantlement Provision (Issue 5)

1. Analysis

TECO's existing depreciation rates and dismantlement provision were approved effective January 1, 2022.[9] On December 27, 2023, the Company filed its 2023 depreciation study and its dismantlement study in Docket No. 20230139-EI. These studies were subsequently consolidated with the current rate case on April 16, 2024. TECO's 2023 depreciation study reflects changes in the Company's plant and reserve balances, and proposes revisions to its current estimates of the depreciation parameters and depreciation rates for various production, transmission, distribution and general accounts. TECO's 2023 dismantlement study reflects updates to its current estimates

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[9] Order No. PSC-2021-0423-S-EI, issued Nov. 10, 2021, in Docket No. 20200264-EI, *In re: Petition for rate increase by Tampa Electric Company.*

of future dismantlement costs and dismantlement provision for the Company's generating facilities.

OPC proposed different estimates of the depreciation parameters and the resulting depreciation rates for solar and battery energy storage equipment-related accounts. FEA proposed different depreciation parameters and the resulting rates for certain other depreciable accounts. OPC also proposed different dismantlement costs and the corresponding accruals.

2. Conclusion

Taking into consideration the aforementioned changes in the Company's plant activities since its last depreciation study, the updated estimates of the future dismantlement costs, and various depreciation and dismantlement-related proposals proffered by the parties, we find that a revision of the existing depreciation rates and dismantlement provisions is necessary. The specific revisions are discussed below in the discussion of Issues 7 and 11.

B. Implementation Date (Issue 6)

1. Analysis

TECO proposed a January 1, 2025, implementation date for the Company's proposed depreciation rates and its proposed dismantlement provision, because this date matches the Company's proposed effective date of its proposed new 2025 customer rates. All intervenors who took a position agreed with TECO's proposal, while FEA and Sierra Club took no position on this issue.

Rule 25-6.0436(4)(d), F.A.C., requires that data submitted in a depreciation study, including plant and reserve balances or company planning involving estimates, must coincide with the effective date of the proposed rates. TECO's supporting data, analyses, and calculations for its proposed depreciation rates, detailed in its 2023 Depreciation Study, are consistent with the Company's proposed implementation date of January 1, 2025. Rule 25-6.04364(3)(k), F.A.C., requires that in a dismantlement study, the proposed provision for dismantlement shall be identified as to the proposed effective date. In its 2023 Dismantlement Study, TECO used January 1, 2025, as the proposed effective date for its proposed accruals related to the dismantlement provision.

2. Conclusion

We find January 1, 2025, is the appropriate implementation date for the new depreciation rates and dismantlement provision.

C. Depreciation Parameters and Rates (Issue 7)

1. Summary of the Issue

Here we address the depreciation parameters and resulting depreciation rates for TECO's depreciable plant accounts that are categorized as production (further classified as steam, other, and solar), transmission, distribution, and general accounts. Our approved depreciation parameters include the survivor curve, which is a pairing of average service life (ASL) with a specific curve shape, an average remaining life (ARL), and an average future net salvage percentage (NS) for each account.[10] The combination of these parameters can be used to provide an account-specific depreciation rate on a going-forward basis, which is the remaining life depreciation rate (depreciation rate). This depreciation rate is designed to recover the remaining unrecovered plant balance, or investment, over the remaining life of the associated investment in the account. The formula for the remaining life depreciation rate is prescribed in the Commission's depreciation rule.[11]

For each plant account, TECO proposed a survivor curve, an ARL, a NS and the resulting depreciation rate, all of which are detailed in TECO's 2023 Depreciation Study. For certain accounts, the parties disagreed with TECO's proposals. In the production plant category, compared with what TECO has proposed, OPC proposed a longer service life for solar and battery energy storage plants, respectively; and FEA proposed a longer service life for the combined cycle plant, as well as different interim survivor curves for four accounts. In the transmission, distribution, and general plant categories, compared with what TECO has proposed, FEA proposed a longer ASL for one account and larger NS for six accounts.

2. Analysis

The following sections present our analyses of the disparate positions taken by TECO and the intervenors on depreciation parameters and resulting depreciation rates in this proceeding.

a. Service Life of Solar Plant

TECO's solar generation depreciation accounts have an existing survivor curve of 35-year ASL with SQ curve shape, denoted as 35-SQ.[12] TECO proposed changing the 35-SQ

[10] For a depreciation account, the ASL is the average number of years that the assets in the account are expected to be in-service. The curve shape is a graphical representation of the retirement pattern for the plant assets in the account. The ARL is the average number of in-service years left for plant currently in service and the NS is gross salvage minus cost of removal of the retired plant assets.

[11] *See* Rule 25-6.0436(1)(e), F.A.C., Remaining Life Rate = (100% - Reserve % - Average Future Net Salvage %) ÷ Average Remaining Life in Years

[12] In depreciation studies, Iowa Curves, published in Bulletin 125, Statistical Analysis of Industrial Reporting, published in 1935, by Robley E. Winfrey of the Iowa State College Engineering Experimental Station, are widely used to depict the retirement pattern of a plant asset. Each curve is denoted by a letter and number. The letter defines when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL, an R curve implies that retirements tend to occur after the ASL, S represents a symmetric curve shape which implies that retirements tend to have equal chances of occurring prior or after the ASL, and SQ represents square curve shape

designation to 30-S3, i.e., using a 30-year ASL with a S3 curve to estimate the solar plant's retirement characteristics. OPC opposed that change, arguing that the currently approved 35-year ASL should be retained, and OPC witness Kollen asserted that TECO has not provided any evidence that it will not operate the existing and new solar assets for 35 years.

In refuting OPC's proposal, TECO witness Allis pointed out that the solar generation's existing 35-year service life is an outcome of its 2021 Settlement Agreement in the previous rate case and the Company had proposed a 30-year life originally in that rate case.[13] He testified that "solar generation is still relatively new, and technology will likely continue to improve, both of which suggest that a shorter life for depreciation purposes would be better than a longer life." Witness Allis also testified that the Federal Energy Regulatory Commission (FERC) would be modifying its treatment of renewable and storage generation under the Uniform System of Accounts and that it is not reasonable to adopt Mr. Kollen's proposal until these changes are implemented.

We agree with witness Allis that solar generation is still relatively new and its technology will likely continue to improve. However, due to the nature of new generation technology, TECO has not retired any of its solar facilities so far, hence, there is not much actual data or experience available to be used as a reference in determining the appropriate service life of this type of generation at the present time.

Witness Allis testified that an upcoming order from FERC will bring accounting changes to the solar generation and a new subaccount would be created. Since the establishment of any accounts/subaccount involves a process of petition for approval,[14] we find that the future new account/subaccount establishment docket will provide for a more informed review of the solar plant accounts' life characteristics to set appropriate depreciation rates. Therefore, we find that retaining the currently approved 35-year service life for solar plant and implementing the 35-S3 survivor curve for the related depreciable accounts are appropriate.

b. Service Life of Battery Energy Storage Equipment

TECO's battery energy storage equipment (BESE) accounts have an existing survivor curve of 10-SQ. As of December 2024, TECO has two BESE facilities that were placed in-service in 2020 and 2024. In 2025, the Company plans to bring another three BESE facilities in-service. TECO proposed to use a 10-S3 survivor curve for the BESE plant account, i.e., modify the retirement dispersion for analysis but retain the estimate of a 10-year service life. OPC asserted that TECO's proposed service life estimate is "unduly short," and proposed an estimate of a 20-year service life instead. On August 22, 2024, TECO filed an "Updated Revenue Requirements" document which noted that the Company agreed with OPC and proposed that the

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which implies that retirements tend to occur at the ASL. The number portion of the Iowa Curve designation indicates how steep or flat the curve's shape is.

[13] The TECO 2021 Settlement Agreement is outlined in Order No. PSC-2021-0423-S-EI, issued Nov. 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company*.

[14] Rule 25-6.0436(3)(b), F.A.C., requires that "[u]pon establishing a new account or subaccount classification, each utility shall request Commission approval of a depreciation rate for the new plant category."

depreciation life of its energy storage assets be 20 years rather than its original proposal of 10 years.

TECO has very limited historical data on the service lives and operations of the BESE assets. A 20-year service life is within the range of the life estimates for BESE assets that TECO's expert witness Allis and his consulting firm have provided for many other utilities across the nation. We also note that the service life of all of TECO's plant assets will be reviewed by this Commission every four years pursuant to Rule 25-6.0436(4)(a), F.A.C. We find that a 20-year service life for TECO's BESE assets is appropriate at this time.

c. Service Life of Combined Cycle Plant

In a depreciation study, assets such as steam or natural gas generation plants for which all assets at a facility are expected to retire concurrently are referred to as "life span property." TECO witness Allis testified that life spans for combined cycle (CC) plants are generally consistent with a 35-year estimate, which is the same estimate as currently used for the Company's CC facilities. He further testified that due to the specifics of each facility, including the configuration of the plant, some estimates are longer than 35 years.

FEA witness Andrews pointed out that TECO's 2023 Depreciation Study indicates that "the Big Bend combined cycle plant (Units 1, 5, & 6) have lifespans of either 35 or 36 years. The Bayside combined cycle plant (Units 1 & 2) have lifespans of 34 and 35 years." He asserted that TECO witness Allis recommended the use of a 40-year life for CC plants in other Florida electric utilities' proceedings.[15] He testified that "[i]n order to be consistent with the lifespan of the Polk combined cycle plant and the other major electric utilities in Florida, I recommend the use of a 40-year life for the Big Bend and Bayside combined cycle plants."

TECO witness Allis disagreed with FEA's life proposal. He explained that his life proposal has taken into consideration the specifics of each generation unit. Witness Allis also pointed out that FEA witness Andrews has not toured any CC facilities or met with TECO subject matter experts on these plants, nor has he provided any discussion of factors that would influence the life span of CC facilities. Witness Allis testified that Bayside Units 1 and 2 are different from many other combined cycle units, and, while some assets are relatively new (constructed in 2003 and 2004), the steam turbines the plant uses were placed in service in the 1960s. He further stated that this will impact the overall life span of the plant and mean that a 40-year life span is likely not attainable. He pointed out that the CC units which have a similar configuration were retired much earlier than the 35-year life span.[16] Witness Allis further testified that the increased adoption of renewable generation can also reduce CC plants' life span due to more frequent cycling to follow electrical load. As the amount of solar energy generated fluctuates, other types of generation assets (such as CC) need to come online quickly to make up

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[15] E.g., Docket No. 20240025-EI, *In re: Petition for rate increase by Duke Energy Florida, LLC.*; Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

[16] As an example, Florida Power & Light Company's Lauderdale Units 4 and 5 were CC plants that "had similar construction in that the Lauderdale units also reused the existing steam turbines that had been placed in service decades earlier. Lauderdale [Units] 4 and 5 were retired in 2018 with life spans of 25 years."

for the loss of solar generation and thus, cycle more frequently which can limit or reduce the life span of a facility.

Witness Allis concluded that all of these factors mean that the operations of TECO's CC plants will likely favor a shorter life, all else equal. Additionally, the witness testified that over the next three decades, there will be significant changes in the electric industry and it is unclear whether CCs could attain longer life spans, at least without major investments. He argued that TECO's past experience shows that it has replaced aging generation when no longer economical, which also favors the 35-year life span.

A 35-year life span for TECO's CC facilities, including the CCs at the Big Bend and Bayside plants, reflects the specific plant conditions of the Company's CC assets and the current CC operating characteristics in general. We find that retaining the currently approved 35-year life span is appropriate.

d. Interim Retirement of Life Span Property Accounts

Interim retirements are the retirements related to assets of a generation facility that do not survive for the entirety of the plant's life span but are replaced or retired during the life span of the facility.[17] For each production account, TECO witness Allis recommended an interim survivor curve to represent the life characteristic of the assets in that account. The only intervenor to propose different interim survivor curves from the Company's recommendation was FEA witness Andrews, who suggested different proposals for four accounts: Boiler Plant Equipment, Structures and Improvements, Fuel Holders, and Prime Movers.

FEA witness Andrews testified that he conducted his own actuarial analysis based on the observed life tables created by TECO witness Allis to determine the interim survivor curve that best fits the significant points of witness Allis' observed life table.[18] He claimed that the interim survivor curves he recommended are a better statistical fit (low SSD) than those curves that witness Allis recommended.[19]

In his rebuttal testimony, TECO witness Allis asserted that Mr. Andrews failed to properly consider the company's historical data and therefore incorrectly projected the experience of older, different technologies onto the company's current generation fleet. TECO

[17] Examples of interim retirements include the retirement of piping, boiler tubes, condensers, turbine blades, and rotors of a generating unit that occur prior to the unit's final retirement date.
[18] Actuarial analysis is commonly used in evaluating the historical asset retirement experience when vintage data is available and sufficient retirement activity is present. Historical data, including plant additions, retirements, and transfers, is organized by the vintage and transaction year to develop an observed life table (OLT) to depict the percentage of the assets surviving at each age interval. The OLT is plotted as a survivor curve and the area under the curve represents the average life of the plant assets in the account being analyzed. An OLT curve is rarely smooth and typically incomplete due to plant assets in the account not reaching their end of life yet. Standard mortality curves, such as the Iowa Curves, are used to compare with, or fit, the OLT curve for this purpose. The ASL and its associated best-fitted Iowa Curve together describes the life estimate of the account.
[19] The SSD is the sum of the squared differences between the Iowa Curves and the significant data points from the observed life tables.

witness Allis further argued this point by stating that FEA witness Andrews' curve fitting "does not consider the relevance and importance of different data points from the historical analysis." He used an example to support the argument: witness Andrews' analysis for Account 341.00 was based on data through approximately age 50, but TECO's current power plants in the accounts being analyzed have all been constructed within the last 30 years. As a result, the data points beyond age 30 do not provide meaningful indications of the retirement experience for the plants currently in service, particularly the type of power plants included in the historical analysis that are much different today than 40 or 50 years ago.

TECO witness Allis concluded his argument by stating that "there are analytical issues with Mr. Andrews' recommendations, which also lead to atypical results. Additionally, Mr. Andrews does not appear to have considered anything beyond the data." Witness Allis claimed that his interim survivor curve recommendations are reasonably consistent with the available data, incorporated knowledge and understanding of the assets, and are consistent with the operation of the types of plants as well; thus, they are better estimates than those of witness Andrews.

We find that TECO witness Allis' arguments have merit and are persuaded by them. Based on the review of the record evidence, we find that TECO's proposed interim survivor curves represent the plant assets' characteristics more closely and, hence, are more reasonable.

e. Average Service Life and Net Salvage of Mass Property Accounts

Plant assets such as meters, poles, and conductors that are continually added and replaced are referred to as "mass property." TECO's depreciable transmission, distribution, and general plant assets were studied as mass property to generate its associated depreciation parameters. For those same mass property accounts, FEA proposed a different ASL for one account and different NS rates for six accounts.

1. ASL Proposal for Account 367.00 – Underground Conductors and Devices

This account is the second largest among the mass property accounts, and the third largest of all of TECO's depreciable accounts. The amount of plant investment booked in the account is $742.4 million as of December 31, 2024. The assets in the account include cable, enclosed switchgears and potheads (insulated terminals for connecting overhead lines and high-voltage underground cables). Typical causes of retirement in the account include failures, dig-ins, and relocations. The average age of retirement in the most recent 10-year period (2013 through 2022) is 21 years.

TECO witness Allis proposes a 35-year life estimate with an R1.5 curve shape for this account. In its 2023 Depreciation Study, the Company indicates that the results of the actuarial analysis and simulated plant record (SPR) analysis both support an ASL in the 35-year range.[20] TECO's study also notes that the 35-R1.5 life estimate is on the shorter end of the industry range, but its estimate is consistent with TECO's historic experience as well as the operating environment in Florida.

FEA witness Andrews disagreed with TECO's life proposal and recommended retaining the existing life estimate of 45-R1.5 which was adopted in TECO's 2021 Settlement Agreement. He asserted that relying on simulated data and the SPR procedure results in understated ASLs, and as the simulations are dependent on the survivor curves used to estimate the data, the results tend to be skewed toward the downside resulting in higher depreciation rates.

TECO witness Allis responded by pointing out that:

> [FEA witness] Andrews provides no support for this statement, and it is not generally consistent with my experience. [. . .] SPR analyses [do] produce results that are more difficult to interpret and require an experienced analyst to recognize the limitations of the analysis. For example, if mortality characteristics are dynamic over time, then the analysis may favor higher or lower mode curves. The selection of higher mode curves in these instances could produce[ ] shorter lives, although lower mode curves would have the opposite effect. [. . .] However, these limitations do not apply for this account to effectively ignore the available analysis, as [witness] Andrews proposes. My recommended survivor curve, supported by the statistical results, uses a mid-mode R1.5 survivor curve.

We note that TECO's 35-year ASL estimate was derived from an actuarial analysis that is based on the Company's actual retirement data, and the outcome of TECO's SPR analysis supports the life estimate resulting from the actuarial analysis. We are also aware that in its last depreciation study that was consolidated with the Company's last rate case, TECO proposed a 40-R1.5 survivor curve for Account 367 based on an actuarial analysis. Further, we have reviewed the potential impacts to the instant rate case, in terms of the adjustments to rate base, net operating income, and revenue requirement that would result from each witness' ASL proposal. Taking into consideration all of these matters, we find a 40-R1.5 survivor curve for Account 367 is appropriate, because it reflects the account's life characteristics, within the

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[20] An actuarial analysis is a method of deriving survivor curves using the average rates at which property of each age group is retired. It is the preferred method when sufficient data are available. The method relates to property groups for which aged accounting experience is available or for which aged accounting experience is developed by statistically aging unaged amounts. TECO currently maintains aged data for all of its accounts.

The SPR analysis is a method used for property groups for which the retirements of property by age are not known. However, it does require continuous records of annual plant activity and year-end plant balances. The method suggests probable survivor curves for a property group by successively applying a number of alternative survivor curves to the group's historical additions in order to simulate the group's surviving balance over a selected period of time. One of the several survivor curves which results in simulated balances that conform most closely to the book balance may be considered to be the survivor curve which the group under study is experiencing.

industry range of the account's life estimates, and it is consistent with this Commission's recognition of the generally accepted principle of gradualism.[21]

2. Net Salvage Proposals

TECO and FEA proposed different NS percentages for 6 disputed accounts: Overhead Conductors and Devices (Transmission); Station Equipment; Poles, Towers, and Fixtures; Overhead Conductors and Devices (Distribution); Underground Conductors and Devices; and Trucks. For each account, FEA proposed a greater NS percentage than that proposed by TECO. For each disputed account listed above, TECO witness Allis reviewed the historical annual NS from 1982 to 2022, the three-year moving averages of the NS from 1982–1984 to 2020–2022, and the latest five-year average of the NS with Account 392 having fewer years of information due to data availability.

FEA witness Andrews focused on the overall net salvage, which is the average of the last 40 years' NS amount.[22] The witness claimed that:

> As the net salvage analysis represents such a small sample size of each account and in order to establish a more reasonable recovery of net salvage costs, I have taken the following general approach to set net salvage rates: The net salvage rate for any account should not exceed (being more negative or less positive) than the overall net salvage rate by more than 1% and the net salvage rate should be a multiple of 5%.

TECO witness Allis disputed FEA's reliance on overall NS rates to estimate future NS and maintained that it was not an appropriate approach. He contended that "[w]hile the overall average is a statistic I rely on, I also consider trends in the data as well as current estimates and estimates for other utilities." Witness Allis claimed that "Tampa Electric's estimates are more reasonable than FEA's because they align more closely with recent trends in net salvage experience, and they more appropriately consider the trend towards increasing cost of removal in the utility industry."

Witness Allis further testified that the removal costs, which is an important component of the NS,[23] have increased in the industry. He then expounded on the reasons behind the increase and pointed out many of them are outside of the Company's control: environmental rules have increased removal costs, permitting requirements have become more restrictive and burdensome, labor costs have increased because of wage increases and a shortage of skilled workers in the

[21] As it pertains to depreciation rate change, "gradualism" is the concept of making smaller adjustments over time as opposed to less frequent, large adjustments. *See* Order No PSC-10-0131-FOF-EI, issued Mar. 5, 2010, in Docket No. 20090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc.*; Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas*; Order No. PSC-2023-0388-FOF-GU, issued Dec. 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System, Inc.*
[22] Except Account 392 which has less years' available data.
[23] *See* Rule 25-6.0436(1)(e),(j), F.A.C.

utility sector, material and equipment costs have increased due to overall inflation and increased demand across various industries.[24]

FEA's general approach, which only focuses on overall net salvage, fails to consider certain factors. By accounting for the recent trends in the activities of cost of removal and the industry experience, TECO provides a more well-rounded analysis of the NS accounts. We find this provides a more accurate picture of future NS. Therefore, we find that TECO's proposed estimates of the future NS are reasonable for this proceeding.

3. Conclusion

Based on the above, we hereby approve the depreciation parameters and resulting depreciation rates for each production, transmission, distribution and general plant account that are presented in Table 1.

[24] Some examples are: disposal requirements for treated wood poles have increased over time; local governments may require work to only be performed at certain hours of the day which increases project costs; municipalities have required restoration of sidewalks or landscaping; increased requirements for traffic control.

Table 1
Depreciation Parameters and Resulting Depreciation Rates

				EXISTING ESTIMATES				STAFF RECOMMENDED ESTIMATES			
		ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
STEAM PRODUCTION PLANT											
BIG BEND POWER PLANT											
	BIG BEND COMMON										
311.00	STRUCTURES AND IMPROVEMENTS	252,807,168	71,630,371	VARIOUS *	(2)	8,089,829	3.20	75-R1.5 *	(5)	6,365,095	2.52
312.00	BOILER PLANT EQUIPMENT	219,407,899	48,398,158	VARIOUS *	(5)	10,092,763	4.60	40-L0 *	(12)	8,358,267	3.81
314.00	TURBOGENERATOR UNITS	28,314,960	(856,157)	VARIOUS *	(6)	877,764	3.10	45-R1 *	(8)	1,104,579	3.90
315.00	ACCESSORY ELECTRIC EQUIPMENT	43,865,595	19,735,461	VARIOUS *	(5)	1,535,296	3.50	50-R1.5 *	(4)	946,080	2.16
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	26,457,683	11,831,648	VARIOUS *	(2)	873,104	3.30	55-R0.5 *	(1)	533,905	2.02
	TOTAL BIG BEND COMMON	*570,853,304*	*150,739,482*			*21,468,756*	*3.77*			*17,307,926*	*3.03*
	BIG BEND UNIT 4										
311.00	STRUCTURES AND IMPROVEMENTS	104,628,976	54,187,413	VARIOUS *	(2)	1,987,951	1.90	75-R1.5 *	(5)	3,653,085	3.49
312.00	BOILER PLANT EQUIPMENT	552,262,972	218,119,144	VARIOUS *	(5)	18,224,678	3.30	40-L0 *	(12)	29,704,405	5.38
314.00	TURBOGENERATOR UNITS	123,977,662	52,223,808	VARIOUS *	(6)	3,967,285	3.20	45-R1 *	(8)	5,780,047	4.66
315.00	ACCESSORY ELECTRIC EQUIPMENT	97,538,411	61,793,800	VARIOUS *	(5)	2,828,614	2.90	50-R1.5 *	(4)	2,728,572	2.80
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	8,248,594	6,056,093	VARIOUS *	(2)	148,475	1.80	55-R0.5 *	(1)	158,757	1.92
	TOTAL BIG BEND UNIT 4	*886,656,615*	*392,380,258*			*27,157,003*	*3.06*			*42,024,866*	*4.74*
TOTAL BIG BEND POWER PLANT		***1,457,509,919***	***543,119,740***			***48,625,759***	***3.34***			***59,332,792***	***4.07***
TOTAL STEAM PRODUCTION PLANT		***1,457,509,919***	***543,119,740***			***48,625,759***	***3.34***			***59,332,792***	***4.07***
OTHER PRODUCTION											
BIG BEND POWER PLANT											
	BIG BEND UNIT 1										
341.00	STRUCTURES AND IMPROVEMENTS	2,290,549	1,536,810	VARIOUS *	0	66,426	2.90	50-R3 *	(10)	78,624	3.43
342.00	FUEL HOLDERS	3,390,810	1,599,040	VARIOUS *	0	98,333	2.90	50-R0.5 *	(3)	75,258	2.22
343.00	PRIME MOVERS	459,001,278	19,610,395	VARIOUS *	0	13,311,037	2.90	50-O1 *	(4)	16,700,144	3.64
345.00	ACCESSORY ELECTRIC EQUIPMENT	546,961	95,858	VARIOUS *	0	15,862	2.90	55-S1 *	(4)	15,995	2.92
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	308,526	245,094	VARIOUS *	0	8,947	2.90	35-L2 *	(3)	8,195	2.66
	TOTAL BIG BEND UNIT 1	*465,538,124*	*23,087,198*			*13,500,605*	*2.90*			*16,878,216*	*3.63*
	BIG BEND UNIT 4										
341.00	STRUCTURES AND IMPROVEMENTS	3,311,083	1,048,804	VARIOUS *	(2)	119,199	3.60	50-R3 *	(10)	112,025	3.38
342.00	FUEL HOLDERS	5,596,201	216,754	VARIOUS *	(5)	145,501	2.60	50-R0.5 *	(3)	249,206	4.45
343.00	PRIME MOVERS	23,563,084	10,732,429	VARIOUS *	(7)	730,456	3.10	50-O1 *	(4)	641,807	2.72
345.00	ACCESSORY ELECTRIC EQUIPMENT	15,256,508	7,575,498	VARIOUS *	(5)	427,182	2.80	55-S1 *	(4)	369,157	2.42
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	510,665	252,987	VARIOUS *	(2)	14,809	2.90	35-L2 *	(3)	15,965	3.13
	TOTAL BIG BEND UNIT 4	*48,237,541*	*19,826,472*			*1,437,147*	*2.98*			*1,388,160*	*2.88*
	BIG BEND UNIT 5										
341.00	STRUCTURES AND IMPROVEMENTS	-	-	VARIOUS *	0	-	2.90	50-R3 *	(10)	-	2.20 **
342.00	FUEL HOLDERS	506,226	(21,322)	VARIOUS *	0	14,681	2.90	50-R0.5 *	(3)	19,124	3.78
343.00	PRIME MOVERS	176,678,691	14,301,530	VARIOUS *	0	5,123,682	2.90	50-O1 *	(4)	6,190,877	3.50
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	VARIOUS *	0	-	2.90	55-S1 *	(4)	-	1.89 **
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	0	-	2.90	35-L2 *	(3)	-	2.94 **
	TOTAL BIG BEND UNIT 5	*177,184,917*	*14,280,209*			*5,138,363*	*2.90*			*6,210,001*	*3.50*
	BIG BEND UNIT 6										
341.00	STRUCTURES AND IMPROVEMENTS	-	-	VARIOUS *	0	-	2.90	50-R3 *	(10)	-	2.20 **
342.00	FUEL HOLDERS	528,138	(3,843)	VARIOUS *	0	15,316	2.90	50-R0.5 *	(3)	19,303	3.65
343.00	PRIME MOVERS	175,430,567	14,231,833	VARIOUS *	0	5,087,486	2.90	50-O1 *	(4)	6,145,998	3.50
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	VARIOUS *	0	-	2.90	55-S1 *	(4)	-	1.89 **
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	0	-	2.90	35-L2 *	(3)	-	2.94 **
	TOTAL BIG BEND UNIT 6	*175,958,705*	*14,227,991*			*5,102,802*	*2.90*			*6,165,301*	*3.50*
TOTAL BIG BEND POWER STATION		***866,919,288***	***71,421,868***			***25,178,917***	***2.90***			***30,641,678***	***3.53***
POLK POWER STATION											
	POLK COMMON										
341.00	STRUCTURES AND IMPROVEMENTS	192,917,190	67,373,353	VARIOUS *	(2)	5,980,433	3.10	50-R3 *	(10)	5,754,293	2.98
342.00	FUEL HOLDERS	12,705,608	3,274,313	VARIOUS *	(5)	381,168	3.00	50-R0.5 *	(3)	403,971	3.18
343.00	PRIME MOVERS	13,916,023	1,969,286	VARIOUS *	(7)	500,977	3.60	50-O1 *	(4)	526,458	3.78
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	-	-	VARIOUS *	(7)	-	3.60	8-L0 *	39	-	7.63 **
345.00	ACCESSORY ELECTRIC EQUIPMENT	14,519,008	4,521,661	VARIOUS *	(5)	522,684	3.60	55-S1 *	(4)	413,046	2.84
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	1,259,508	68,358	VARIOUS *	(2)	70,532	5.60	35-L2 *	(3)	58,857	4.67
	TOTAL POLK COMMON	*235,317,337*	*77,206,969*			*7,455,794*	*3.17*			*7,156,625*	*3.04*
	POLK UNIT 1 GASIFIER										
341.00	STRUCTURES AND IMPROVEMENTS	53,047,915	28,573,732	VARIOUS *	(2)	1,962,773	3.70	50-R3 *	(10)	2,600,784	4.90
342.00	FUEL HOLDERS	248,976,996	152,814,023	VARIOUS *	(5)	10,208,057	4.10	50-R0.5 *	(3)	9,277,733	3.73
343.00	PRIME MOVERS	148,649,197	88,650,997	VARIOUS *	(7)	6,837,863	4.60	50-O1 *	(4)	5,924,903	3.99
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	15,096,276	3,996,254	VARIOUS *	(7)	694,429	4.60	8-L0 *	39	1,079,187	7.15
345.00	ACCESSORY ELECTRIC EQUIPMENT	60,548,847	45,710,331	VARIOUS *	(5)	1,998,112	3.30	55-S1 *	(4)	1,535,629	2.54
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	6,316,782	3,118,987	VARIOUS *	(2)	265,305	4.20	35-L2 *	(3)	333,396	5.28
	TOTAL POLK UNIT 1 GASIFIER	*532,636,013*	*322,864,325*			*21,966,539*	*4.12*			*20,751,632*	*3.90*
	POLK UNIT 2										
341.00	STRUCTURES AND IMPROVEMENTS	2,342,155	1,331,857	VARIOUS *	(2)	60,896	2.60	50-R3 *	(10)	52,846	2.26
342.00	FUEL HOLDERS	2,365,638	690,923	VARIOUS *	(5)	101,722	4.30	50-R0.5 *	(3)	72,797	3.08
343.00	PRIME MOVERS	28,974,176	9,221,430	VARIOUS *	(7)	1,419,735	4.90	50-O1 *	(4)	894,045	3.09
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	7,088,119	1,558,312	VARIOUS *	(7)	347,318	4.90	8-L0 *	39	518,844	7.32
345.00	ACCESSORY ELECTRIC EQUIPMENT	19,207,796	11,226,500	VARIOUS *	(5)	653,065	3.40	55-S1 *	(4)	370,589	1.93
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	173,210	139,897	VARIOUS *	(2)	2,945	1.70	35-L2 *	(3)	2,604	1.50
	TOTAL POLK UNIT 2	*60,151,095*	*24,168,919*			*2,585,681*	*4.30*			*1,911,725*	*3.18*
	POLK UNIT 3										
341.00	STRUCTURES AND IMPROVEMENTS	10,708,677	6,000,960	VARIOUS *	(2)	278,426	2.60	50-R3 *	(10)	243,411	2.27
342.00	FUEL HOLDERS	1,514,895	645,094	VARIOUS *	(5)	48,477	3.20	50-R0.5 *	(3)	38,749	2.56
343.00	PRIME MOVERS	32,249,524	21,819,630	VARIOUS *	(7)	1,160,983	3.60	50-O1 *	(4)	509,560	1.58
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	6,150,760	1,613,264	VARIOUS *	(7)	221,427	3.60	8-L0 *	39	357,045	5.80
345.00	ACCESSORY ELECTRIC EQUIPMENT	9,125,741	5,945,160	VARIOUS *	(5)	346,778	3.80	55-S1 *	(4)	151,781	1.66
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	432,910	283,697	VARIOUS *	(2)	9,524	2.20	35-L2 *	(3)	10,560	2.44
	TOTAL POLK UNIT 3	*60,182,507*	*36,307,805*			*2,065,615*	*3.43*			*1,311,106*	*2.18*
	POLK UNIT 4										
341.00	STRUCTURES AND IMPROVEMENTS	5,818,841	2,412,947	VARIOUS *	(2)	157,109	2.70	50-R3 *	(10)	159,639	2.74
342.00	FUEL HOLDERS	2,369,199	239,613	VARIOUS *	(5)	66,338	2.80	50-R0.5 *	(3)	92,039	3.88
343.00	PRIME MOVERS	21,726,818	7,378,258	VARIOUS *	(7)	1,021,160	4.70	50-O1 *	(4)	651,719	3.00
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	6,688,260	1,033,396	VARIOUS *	(7)	314,348	4.70	8-L0 *	39	508,588	7.60
345.00	ACCESSORY ELECTRIC EQUIPMENT	5,586,747	3,437,915	VARIOUS *	(5)	139,669	2.50	55-S1 *	(4)	97,706	1.75
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	(2)	-	3.60	35-L2 *	(3)	-	2.94 **
	TOTAL POLK UNIT 4	*42,189,865*	*14,502,128*			*1,698,624*	*4.03*			*1,509,691*	*3.58*
	POLK UNIT 5										
341.00	STRUCTURES AND IMPROVEMENTS	5,748,795	2,423,788	VARIOUS *	(2)	155,217	2.70	50-R3 *	(10)	156,245	2.72
342.00	FUEL HOLDERS	2,759,831	767,540	VARIOUS *	(5)	102,114	3.70	50-R0.5 *	(3)	86,498	3.13
343.00	PRIME MOVERS	19,842,748	6,026,359	VARIOUS *	(7)	992,137	5.00	50-O1 *	(4)	626,237	3.16
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	5,380,612	823,354	VARIOUS *	(7)	269,031	5.00	8-L0 *	39	427,621	7.95
345.00	ACCESSORY ELECTRIC EQUIPMENT	5,471,617	3,427,254	VARIOUS *	(5)	142,262	2.60	55-S1 *	(4)	93,367	1.71
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	(2)	-	3.60	35-L2 *	(3)	-	2.94 **
	TOTAL POLK UNIT 5	*39,203,602*	*13,468,294*			*1,660,761*	*4.24*			*1,389,968*	*3.55*
	POLK UNIT 6										
341.00	STRUCTURES AND IMPROVEMENTS	13,374,554	4,266,582	VARIOUS *	(2)	347,738	2.60	50-R3 *	(10)	391,802	2.93
342.00	FUEL HOLDERS	216,762,618	45,118,089	VARIOUS *	(5)	6,502,879	3.00	50-R0.5 *	(3)	7,313,112	3.37
343.00	PRIME MOVERS	226,870,880	47,795,255	VARIOUS *	(7)	7,032,997	3.10	50-O1 *	(4)	7,905,482	3.48
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	-	-	VARIOUS *	(7)	-	3.10	8-L0 *	39	-	7.63 **
345.00	ACCESSORY ELECTRIC EQUIPMENT	18,338,595	4,565,339	VARIOUS *	(5)	550,158	3.00	55-S1 *	(4)	557,097	3.04
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	141,626	30,886	VARIOUS *	(2)	4,249	3.00	35-L2 *	(3)	5,253	3.71
	TOTAL POLK UNIT 6	*475,488,274*	*101,776,150*			*14,438,021*	*3.04*			*16,172,746*	*3.40*
TOTAL POLK POWER STATION		***1,445,168,694***	***590,294,591***			***51,871,035***	***3.59***			***50,203,493***	***3.47***
BAYSIDE POWER STATION											
	BAYSIDE COMMON										
341.00	STRUCTURES AND IMPROVEMENTS	107,128,094	27,808,472	VARIOUS *	(2)	3,642,355	3.40	50-R3 *	(10)	3,962,695	3.70
342.00	FUEL HOLDERS	45,562,572	3,913,589	VARIOUS *	(5)	1,366,877	3.00	50-R0.5 *	(3)	1,942,025	4.26
343.00	PRIME MOVERS	31,034,701	7,585,820	VARIOUS *	(7)	1,706,909	5.50	50-O1 *	(4)	1,145,189	3.69
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	28,838,295	6,785,680	VARIOUS *	(7)	1,586,106	5.50	8-L0 *	39	2,131,298	7.39

				EXISTING ESTIMATES				STAFF RECOMMENDED ESTIMATES			
		ORIGINAL COST AS OF DECEMBER 31, 2024	BOOK DEPRECIATION RESERVE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL DEPRECIATION ACCRUALS	ANNUAL DEPRECIATION RATE
345.00	ACCESSORY ELECTRIC EQUIPMENT	29,466,323	14,150,248	VARIOUS *	(5)	972,389	3.30	55-S1 *	(4)	723,770	2.46
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	11,303,633	5,408,948	VARIOUS *	(2)	452,145	4.00	35-L2 *	(3)	368,864	3.26
	TOTAL BAYSIDE COMMON	*253,333,618*	*65,652,757*			*9,726,781*	*3.84*			*10,273,841*	*4.06*
	BAYSIDE UNIT 1										
341.00	STRUCTURES AND IMPROVEMENTS	21,251,285	9,610,255	VARIOUS *	(2)	765,046	3.60	50-R3 *	(10)	1,040,526	4.90
342.00	FUEL HOLDERS	92,211,219	38,522,972	VARIOUS *	(5)	3,688,449	4.00	50-R0.5 *	(3)	4,339,322	4.71
343.00	PRIME MOVERS	201,291,115	94,122,674	VARIOUS *	(7)	12,278,758	6.10	50-O1 *	(4)	8,966,544	4.45
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	56,011,118	13,964,111	VARIOUS *	(7)	3,416,678	6.10	8-L0 *	39	4,326,054	7.72
345.00	ACCESSORY ELECTRIC EQUIPMENT	39,466,426	23,489,843	VARIOUS *	(5)	1,618,123	4.10	55-S1 *	(4)	1,325,924	3.36
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	1,175,705	673,431	VARIOUS *	(2)	37,623	3.20	35-L2 *	(3)	50,474	4.29
	TOTAL BAYSIDE UNIT 1	*411,406,868*	*180,383,286*			*21,804,677*	*5.30*			*20,048,844*	*4.87*
	BAYSIDE UNIT 2										
341.00	STRUCTURES AND IMPROVEMENTS	27,131,136	14,552,665	VARIOUS *	(2)	949,590	3.50	50-R3 *	(10)	1,151,475	4.24
342.00	FUEL HOLDERS	142,497,135	42,388,039	VARIOUS *	(5)	5,557,388	3.90	50-R0.5 *	(3)	7,986,535	5.60
343.00	PRIME MOVERS	252,939,409	113,313,487	VARIOUS *	(7)	15,682,243	6.20	50-O1 *	(4)	11,662,266	4.61
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	71,747,592	16,090,514	VARIOUS *	(7)	4,448,351	6.20	8-L0 *	39	5,875,906	8.19
345.00	ACCESSORY ELECTRIC EQUIPMENT	45,204,446	25,620,125	VARIOUS *	(5)	1,853,382	4.10	55-S1 *	(4)	1,618,192	3.58
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	1,455,592	853,789	VARIOUS *	(2)	48,035	3.30	35-L2 *	(3)	60,212	4.14
	TOTAL BAYSIDE UNIT 2	*540,975,310*	*212,818,619*			*28,538,989*	*5.28*			*28,354,586*	*5.24*
	BAYSIDE UNIT 3										
341.00	STRUCTURES AND IMPROVEMENTS	656,349	75,171	VARIOUS *	(2)	22,972	3.50	50-R3 *	(10)	27,844	4.24
342.00	FUEL HOLDERS	3,940,543	1,279,927	VARIOUS *	(5)	126,097	3.20	50-R0.5 *	(3)	127,294	3.23
343.00	PRIME MOVERS	15,871,413	9,341,596	VARIOUS *	(7)	492,014	3.10	50-O1 *	(4)	336,212	2.12
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	22,955	7,747	VARIOUS *	(7)	712	3.10	8-L0 *	39	1,148	5.00
345.00	ACCESSORY ELECTRIC EQUIPMENT	14,153,816	6,496,955	VARIOUS *	(5)	382,153	2.70	55-S1 *	(4)	363,528	2.57
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	905	487	VARIOUS *	(2)	31	3.40	35-L2 *	(3)	26	2.87
	TOTAL BAYSIDE UNIT 3	*34,645,981*	*17,201,883*			*1,023,979*	*2.96*			*856,052*	*2.47*
	BAYSIDE UNIT 4										
341.00	STRUCTURES AND IMPROVEMENTS	242,334	(73,139)	VARIOUS *	(2)	12,359	5.10	50-R3 *	(10)	14,661	6.05
342.00	FUEL HOLDERS	3,372,331	1,418,335	VARIOUS *	(5)	107,915	3.20	50-R0.5 *	(3)	94,839	2.81
343.00	PRIME MOVERS	15,850,671	9,597,763	VARIOUS *	(7)	507,221	3.20	50-O1 *	(4)	323,330	2.04
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	42,590	13,833	VARIOUS *	(7)	1,363	3.20	8-L0 *	39	2,177	5.11
345.00	ACCESSORY ELECTRIC EQUIPMENT	4,168,999	2,059,329	VARIOUS *	(5)	116,732	2.80	55-S1 *	(4)	101,265	2.43
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	905	487	VARIOUS *	(2)	31	3.40	35-L2 *	(3)	26	2.87
	TOTAL BAYSIDE UNIT 4	*23,677,829*	*13,016,608*			*745,621*	*3.15*			*536,298*	*2.26*
	BAYSIDE UNIT 5										
341.00	STRUCTURES AND IMPROVEMENTS	793,114	(27,676)	VARIOUS *	(2)	34,897	4.40	50-R3 *	(10)	38,532	4.86
342.00	FUEL HOLDERS	2,279,060	834,227	VARIOUS *	(5)	75,209	3.30	50-R0.5 *	(3)	69,477	3.05
343.00	PRIME MOVERS	15,109,733	8,264,764	VARIOUS *	(7)	513,731	3.40	50-O1 *	(4)	349,735	2.31
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	3,746,424	2,152,192	VARIOUS *	(7)	127,378	3.40	8-L0 *	39	41,088	1.10
345.00	ACCESSORY ELECTRIC EQUIPMENT	10,386,138	6,696,976	VARIOUS *	(5)	280,426	2.70	55-S1 *	(4)	182,915	1.76
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	VARIOUS *	(2)	-	3.90	35-L2 *	(3)	-	2.94 **
	TOTAL BAYSIDE UNIT 5	*32,314,469*	*17,920,483*			*1,031,641*	*3.19*			*681,747*	*2.11*
	BAYSIDE UNIT 6										
341.00	STRUCTURES AND IMPROVEMENTS	2,656,232	695,088	VARIOUS *	(2)	82,343	3.10	50-R3 *	(10)	96,189	3.62
342.00	FUEL HOLDERS	1,545,429	640,223	VARIOUS *	(5)	57,181	3.70	50-R0.5 *	(3)	43,912	2.84
343.00	PRIME MOVERS	17,513,069	11,503,619	VARIOUS *	(7)	472,853	2.70	50-O1 *	(4)	315,318	1.80
343.10	PRIME MOVERS - CONTRACTUAL SERVICE AGREEMENTS	11,562	4,307	VARIOUS *	(7)	312	2.70	8-L0 *	39	509	4.40
345.00	ACCESSORY ELECTRIC EQUIPMENT	14,326,608	7,178,379	VARIOUS *	(5)	401,145	2.80	55-S1 *	(4)	344,701	2.41
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT	11,736	5,890	VARIOUS *	(2)	258	2.20	35-L2 *	(3)	364	3.10
	TOTAL BAYSIDE UNIT 6	*36,064,635*	*20,027,505*			*1,014,092*	*2.81*			*800,993*	*2.22*
TOTAL BAYSIDE POWER STATION		***1,332,418,710***	***527,021,142***			***63,885,780***	***4.79***			***61,552,361***	***4.62***
TOTAL OTHER PRODUCTION PLANT		***3,644,506,692***	***1,188,737,602***			***140,935,732***	***3.87***			***142,397,532***	***3.91***
SOLAR SITES											
341.00	STRUCTURES AND IMPROVEMENTS	389,630,579	51,744,519	35-SQ	0	11,299,287	2.90	35-S3	0	11,009,647	2.83
343.00	PRIME MOVERS	1,110,482,450	97,011,381	35-SQ	0	32,203,991	2.90	35-S3	0	31,790,184	2.86
345.00	ACCESSORY ELECTRIC EQUIPMENT	267,298,628	35,783,835	35-SQ	0	7,751,660	2.90	35-S3	0	7,570,791	2.83
348.00	ENERGY STORAGE EQUIPMENT	29,513,911	4,476,523	10-SQ	0	2,951,391	10.00	20-S3	0	1,372,664	4.65
TOTAL SOLAR SITES		***1,796,925,568***	***189,016,259***			***54,206,329***	***2.90***			***51,743,286***	***2.88***
DC MICRO GRID											
341.00	STRUCTURES AND IMPROVEMENTS	-	-	30-SQ	0	-	3.33	35-S3	0	-	2.86 **
343.00	PRIME MOVERS	929,495	56,025	30-SQ	0	30,952	3.33	35-S3	0	26,884	2.89
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	30-SQ	0	-	3.33	35-S3	0	-	2.86 **
348.00	ENERGY STORAGE EQUIPMENT	9,135	1,773	10-SQ	0	913	10.00	20-S3	0	420	4.60
TOTAL DC MICRO GRID		***938,629***	***57,798***			***31,865***	***2.90***			***27,304***	***2.91***
MACDILL AIR FORCE BASE											
341.00	STRUCTURES AND IMPROVEMENTS	-	-	n/a	n/a	-	n/a	50-R3 *	(10)	-	2.20 **
343.00	FUEL HOLDERS	-	-	n/a	n/a	-	n/a	50-R0.5 *	(3)	-	2.06 **
343.00	PRIME MOVERS	-	-	n/a	n/a	-	n/a	50-O1 *	(4)	-	2.08 **
345.00	ACCESSORY ELECTRIC EQUIPMENT	-	-	n/a	n/a	-	n/a	55-S1 *	(4)	-	1.89 **
345.00	MISCELLANEOUS POWER PLANT EQUIPMENT	-	-	n/a	n/a	-	n/a	35-L2 *	(3)	-	2.94 **
348.00	ENERGY STORAGE EQUIPMENT	-	-	n/a	n/a	-	n/a	20-S3 *	0	-	5.00 **
TOTAL MACDILL AIR FORCE BASE		***-***	***-***			***-***				***-***	
TOTAL PRODUCTION PLANT		***6,899,880,808***	***1,920,931,398***			***243,799,685***	***3.50***			***253,500,914***	***3.67***
TRANSMISSION											
350.01	LAND RIGHTS	12,162,254	5,088,906	75-SQ	0	158,109	1.30	75-S4	(10)	187,802	1.54
351.00	ENERGY STORAGE EQUIPMENT	-	-	10-SQ	0	-	10.00	20-S3	0	-	5.00 **
352.00	STRUCTURES AND IMPROVEMENTS	76,177,081	16,085,642	60-R3	(5)	1,371,187	1.80	60-R3	(25)	1,650,724	2.17
353.00	STATION EQUIPMENT	454,634,881	97,479,849	45-S0	(5)	10,911,237	2.40	45-S0	(5)	10,713,107	2.36
354.00	TOWERS AND FIXTURES	5,092,061	5,281,270	55-R5	(15)	142,578	2.80	55-R4	(15)	65,444	1.29
355.00	POLES AND FIXTURES	504,990,597	132,990,187	50-R2	(40)	14,139,737	2.80	50-R1	(50)	14,415,875	2.85
356.00	OVERHEAD CONDUCTORS AND DEVICES	187,307,468	30,104,135	55-R2	(40)	5,431,917	2.90	55-R2	(50)	5,600,738	2.99
356.01	CLEARING RIGHTS-OF-WAY	2,110,610	1,797,133	50-L4	0	33,770	1.60	55-R4	0	21,442	1.02
357.00	UNDERGROUND CONDUIT	4,322,861	1,844,686	60-R5	0	73,489	1.70	60-R4	0	78,622	1.82
358.00	UNDERGROUND CONDUCTORS AND DEVICES	12,346,787	3,958,270	50-R5	0	333,363	2.70	50-R4	(20)	345,682	2.80
359.00	ROADS AND TRAILS	19,965,710	3,263,950	65-SQ	0	319,451	1.60	65-R4	(10)	354,336	1.77
TOTAL TRANSMISSION		***1,279,110,311***	***297,894,028***			***32,914,838***	***2.57***			***33,433,772***	***2.61***
DISTRIBUTION											
361.00	STRUCTURES AND IMPROVEMENTS	33,964,616	9,867,022	60-R3	(5)	611,363	1.80	60-R3	(40)	875,138	2.58
362.00	STATION EQUIPMENT	323,608,732	79,668,418	45-R1	(10)	8,090,218	2.50	45-R1	(20)	8,915,715	2.76
363.00	ENERGY STORAGE EQUIPMENT	-	-	10-SQ	0	-	10.00	20-S3	0	-	5.00 **
364.00	POLES, TOWERS AND FIXTURES	475,405,746	180,542,111	40-R3	(50)	17,590,013	3.70	35-R2.5	(75)	25,258,548	5.31
365.00	OVERHEAD CONDUCTORS AND DEVICES	290,431,972	153,457,026	45-R1	(20)	6,389,503	2.20	50-R1.5	(30)	6,764,399	2.33
366.00	UNDERGROUND CONDUIT	441,958,093	96,115,688	60-R3	(5)	7,513,288	1.70	60-R4	(5)	7,800,303	1.76
367.00	UNDERGROUND CONDUCTORS AND DEVICES	742,409,241	36,671,003	45-R1.5	(5)	17,075,413	2.30	40-R1.5	(15)	21,823,703	2.94
368.00	LINE TRANSFORMERS	995,139,376	367,078,001	30-S5	(20)	44,781,272	4.50	30-S2	(20)	38,995,250	3.92
369.00	SERVICES - OVERHEAD	84,774,891	66,604,199	45-R3	(20)	1,610,723	1.90	45-R3	(30)	1,980,162	2.34
369.02	SERVICES - UNDERGROUND	152,864,831	74,858,129	45-R3	(10)	3,515,891	2.30	45-R3	(20)	4,036,419	2.64
370.00	METERS - ANALOG AND AMR	18,761,082	5,346,434	20-R2	(30)	1,482,126	7.90	20-R2	(30)	1,369,998	7.30
370.01	METERS - AMI	115,201,620	7,017,790	15-R2	(30)	10,022,541	8.70	15-R2	(30)	12,423,352	10.78
370.10	EV CHARGERS	7,247,338	682,788	10-SQ	0	724,734	10.00	10-R2.5	0	728,585	10.05
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	388,101,236	127,676,497	30-L1	(10)	10,866,835	2.80	27-L1	(10)	14,168,317	3.65
373.02	STREET LIGHTING AND SIGNAL SYSTEMS - LS2	19,223,926	951,455	30-L1	(10)	538,270	2.80	27-L1	(10)	783,658	4.08
TOTAL DISTRIBUTION		***4,089,092,702***	***1,206,536,561***			***130,812,190***	***3.20***			***145,923,547***	***3.57***
GENERAL PLANT											
390.00	STRUCTURES AND IMPROVEMENTS	186,199,344	51,544,895	60-R2	(4)	2,606,791	1.40	60-R2	(10)	3,169,445	1.70
392.02	LIGHT TRUCKS - ENERGY DELIVERY	32,079,048	7,792,221	13-S4	15	2,405,929	7.50	11-R1.5	20	2,236,673	6.97
392.03	HEAVY TRUCKS - ENERGY DELIVERY	76,555,659	28,234,266	17-S5	10	3,980,894	5.20	16-L2	20	3,192,482	4.17
392.12	LIGHT TRUCKS - ENERGY SUPPLY	5,328,561	2,181,642	12-R3	15	325,042	6.10	11-R1.5	20	302,062	5.67
392.13	HEAVY TRUCKS - ENERGY SUPPLY	1,055,855	271,361	25-S5	10	50,681	4.80	16-L2	20	63,632	6.03
397.25	COMMUNICATION EQUIPMENT- FIBER	44,397,245	27,514,234	20-R4	(5)	1,287,520	2.90	25-S2	(5)	1,276,077	2.87
TOTAL GENERAL PLANT		***345,615,712***	***117,538,618***			***10,656,857***	***3.08***			***10,240,371***	***2.96***
TOTAL TRANSMISSION, DISTRIBUTION AND GENERAL PLANT		**5,713,818,725**	**1,621,969,208**			**174,383,885**	**3.05**			**189,597,690**	**3.32**
TOTAL DEPRECIABLE PLANT		**12,613,699,533**	**3,542,900,606**			**418,183,570**	**3.32**			**443,098,604**	**3.51**

* CURVE SHOWN IS INTERIM SURVIVOR CURVE. LIFE SPAN METHOD IS USED.
** CALCULATED DEPRECIATION RATE TO BE APPLIED TO FUTURE INSTALLED PLANT IN-SERVICE

D. Reserve Imbalance (Issue 8)

1. Analysis

Our electric utility depreciation rule, Rule 25-6.0436(1)(k), F.A.C., provides that an account's theoretical reserve amount is determined by the account's book investment minus the account's future depreciation accruals and future net salvage. The reserve imbalance of an account is the difference between the account's book reserve and its calculated theoretical reserve. If the book reserve amount is larger than the theoretical reserve amount for a particular account, then this account presents a reserve surplus at a specific point in time. If the book reserve amount is less than the theoretical reserve amount, the account presents a deficit.

Based on his proposed depreciation parameters and depreciation rate for each depreciable account, TECO witness Allis calculated the Company's theoretical depreciation reserve imbalance to be a deficiency (or deficit) of $166.9 million, as of December 31, 2024. On August 22, 2024, TECO filed documents supporting an updated revenue requirement, which noted that "the Company agrees and proposes that the depreciation life of its energy storage assets be 20 years rather than its original proposal of 10 years." This revision of the depreciation life for the energy storage assets changes the calculated theoretical reserve and the reserve imbalance of the energy storage account.

2. Conclusion

We have reviewed TECO's proposed theoretical depreciation reserve imbalance for each depreciable account. We find that the theoretical reserve imbalance should reflect the impact of the aforementioned change in the depreciation life of TECO's energy storage assets. Because of our above approval of a longer service life than TECO's proposal for the solar plant assets and the underground conductors and devices plant assets in Account 367, we have calculated the corresponding adjustments to TECO's proposed theoretical reserve imbalances, and the results are presented in Table 2.

Table 2
Adjustment to
TECO's Proposed Theoretical Reserve Imbalance

	TECO Proposed ($)	Final Approved ($)	Adjustment ($)
Solar Sites	(24,586,766)	5,292,480	29,879,249
Energy Storage	(678,593)	1,873,012	2,551,605
Account 367 – UG Conductors/Devices	(66,102,061)	(54,255,569)	11,846,492
Total	(91,367,423)	(47,090,077)	44,277,346

Table 3 shows our approved theoretical reserve imbalances for each category of TECO's plant accounts, with a total amount of the imbalance being a deficiency of $122.6 million. These are the results of applying the formula prescribed in Rule 25-6.0436(1)(k), F.A.C., to the depreciation parameters and resulting depreciation rates we approved above.

Table 3
Approved Theoretical Reserve Imbalance (as of 12/31/2024)

Account Category	TECO Proposed ($)	Final Approved ($)	Adjustment ($)
Production	(134,187,005)	(101,756,150)	32,430,855
Transmission	586,441	586,441	-
Distribution	(62,067,348)	(50,220,855)	11,846,492
General	28,747,422	28,747,422	-
Total Depreciable Plant	(166,920,489)	(122,643,143)	44,277,347

E. Corrective Reserve Measures (Issue 9)

1. Analysis

TECO witness Allis proposed to address the reserve imbalances through the remaining life technique, arguing in most jurisdictions this is the approach rather than an explicit adjustment. He testified the remaining life technique is a self-correcting mechanism that will increase or decrease depreciation expense to account for any imbalances between book and theoretical reserves, and that TECO's 2023 Depreciation Study uses this technique and therefore no adjustments are needed. All the intervenors who took a position also proposed to use the remaining life technique as the corrective measure.

2. Conclusion

We agree with TECO and the intervenors' proposal, because the remaining life approach is the most often-used method to correct the reserve imbalances. All of the depreciation rates that we previously approved are remaining life depreciation rates, therefore these rates will automatically correct the reserve imbalance over the remaining life of the plant assets. Furthermore, the total amount of reserve imbalances identified, in the amount of negative $122.6 million (a deficit), is approximately three percent of either the book reserve or the theoretical reserve. Based on the aforementioned, we hereby approve the use of the remaining life technique to correct the depreciation reserve imbalances identified above in the previous issue.

F. Investment Tax Credits and Excess Deferred Income Taxes (Issue 10)

1. Analysis

All parties who took a position on this issue agree that the current amortization of Investment Tax Credits (ITCs) and flow back of Excess Deferred Income Taxes (EDITs) should be revised to reflect the approved depreciation rates. OPC also argued that the ITCs should reflect OPC's position regarding the proper treatment of ITCs related to TECO's battery storage assets addressed later herein. Here we address setting the ITC amortization period and flow back of EDITs to match the book depreciation lives that are approved above.

Revising a utility's book depreciation lives generally results in a change in its rate of ITC amortization and flow back of EDITs in order to comply with the normalization requirements of the Internal Revenue Code (IRC or Code) set forth in Federal Tax Regulations,[25] U.S. Code Sections 168(f)(2) and (i)(9),[26] former IRC Sections 167(l), and 46(f),[27] and Section 203(e) of the Tax Reform Act of 1986 (the Act).[28]

Former IRC Section 46(f)(6), indicated that the amortization of ITC should be determined by the period of time actually used in computing depreciation expense for ratemaking purposes and on the regulated books of the utility.[29] While Section 46(f)(6) was repealed, under IRC Section 50(d)(2), the terms of former IRC Section 46(f)(6) remain applicable to public utility property for which a regulated utility previously claimed ITCs. Because we are approving changes to the Company's remaining lives, it is also important to change the amortization of ITCs and EDITs to avoid violation of the provisions of IRC Section 50(d)(2) for ITCs, and IRC Section 168(i)(9), former Section 167(l), and Section 13001(d) of the Tax Change and Jobs Act for EDITs, and their underlying Treasury Regulations. The consequence of an ITC or EDIT normalization violation is a repayment of unamortized ITC balances to the IRS and the inability to utilize accelerated depreciation. Therefore, the current amortization of ITCs and any flow back of EDITs shall be revised to match the actual recovery periods for the related property. The Company shall file detailed calculations of the revised ITC amortization and flow back of EDITs at the same time it files its earnings surveillance report as specified in Rule 25-6.1352, F.A.C.

The Inflation Reduction Act of 2022 (IRA) was signed into law on August 16, 2022, and changed Section 48 of the IRC.[30] As discussed above, prior to the IRA, IRC Section 50(d)(2) required that ITCs had to be normalized, that is, the benefit of the ITC could not be flowed back to the customers at a rate greater than the depreciation rates established by the regulating authority. Under the revised Code, a utility can choose to opt out of the normalization rules for ITCs created by investment in energy storage.[31] Therefore, the amortization of ITCs related to TECO's battery storage investment do not have to be adjusted to match the depreciation rates approved by us if TECO chooses to opt out of the normalization requirements required by Section 50(d)(2) of the IRC. Elsewhere, we order that the ITCs related to TECO's battery storage investment be amortized over five years but be treated as having a 20-year depreciation life for

[25] 26 C.F.R. §§ 1.168 *et seq*; 26 C.F.R. §§ 1.167 *et seq*; 26 C.F.R. §§ 1.46 *et seq*.
[26] 26 U.S.C. § 168(f)(2), (i)(9).
[27] Under IRC Section 50(d)(2), the terms of former 26 U.S.C. § 167(l) and § 46(f), which were repealed by the Revenue Reconciliation Act of 1990 (Pub. L. No. 101-508, § 11812(a)(1–2)(1990)), remain applicable to public utility property for which a regulated utility previously claimed ITCs, which is the case here. (I.R.S. Priv. Ltr. Rul. 200933023, 1n.1 (May 7, 2009)).
[28] Tax Reform Act of 1986, Pub. L. No. 99-514 (100 Stat. 2085, 2146) (1986).
[29] Former 26 U.S.C. § 46(f)(6) (establishing proper determination of ratable portion).
[30] H.R. 5376; Inflation Reduction Act of 2022; 26 U.S.C. § 48.
[31] 26 U.S.C. §§ 48, 168.

the same battery storage assets. Therefore, by our approval to set the battery storage life at a different period as the depreciation life, TECO is also required to opt out of the normalization requirements in Section 50(d)(2), only for the Company's battery storage assets, to avoid a normalization violation.

2. Conclusion

The current amortization of ITCs and any flow back of EDITs shall be revised to match the actual recovery periods for the related property, except for the ITCs related to TECO's battery storage assets. The Company shall file detailed calculations of the revised ITC amortization and flow back of EDITs at the same time it files its earnings surveillance report as specified in Rule 25-6.1352, F.A.C.

G. Dismantlement Annual Accrual (Issue 11)

1. Analysis

The methodologies for performing an electric utility's dismantlement study and determining the annual dismantlement accrual are codified in Rule 25-6.04364, F.A.C. The rule outlines three elements as the dependent factors in calculating the dismantlement accrual: estimated base costs for dismantlement, a contingency factor, and projected escalations. The fixed accrual amount is based on a four-year average of the accruals related to the years between depreciation study reviews. Utilities are required to provide updated dismantlement studies at least once every four years in conjunction with their depreciation study.[32] The purpose of these studies is to reflect changes in dismantlement cost estimates, inflation, regulatory or environmental requirements, and any newly discovered public health and safety issues since its last dismantlement study. TECO filed its 2023 dismantlement study, pursuant to Rule 25-6.04364(3), F.A.C.[33]

TECO retained the 1898 & Co. consulting firm to conduct the 2023 Dismantlement Study (Study).[34] The Study results in a recommendation regarding the base costs, in 2023 dollars, with consideration of dismantlement for all generation units and common facilities at the end of their corresponding useful lives.[35] The Study updates the costs presented in the 2020 dismantlement study, which was also conducted by 1898 & Co., with consideration of changes to market conditions, physical changes that have occurred at the plants, and incorporating new facilities that have been constructed or acquired since 2020.

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[32] These policies were codified in Rule 25-6.04364(3), (4), (7), F.A.C.
[33] TECO's 2020 depreciation and dismantlement studies were approved by Order No. PSC-2021-0423-S-EI. The Company's 2023 depreciation and dismantlement studies were filed on December 27, 2023, in Docket. No. 20230139-EI, which were subsequently consolidated with the instant proceeding.
[34] The Study is also referred to as "TECO Decommissioning Cost Estimate Study, Tampa Electric Company 2023 Fleet Decommissioning Study" by1898 & Co.
[35] The base cost is net of salvage value for scrap materials at each plant.

Using the base costs provided in the Study, TECO calculated its proposed annual accrual for dismantlement. The Company applied a contingency factor and the projected inflation escalators to derive the future costs as of the estimated date of dismantlement. The future costs, less the amount recovered to date, were discounted over the remaining life of each generation unit/plant site to determine the fixed dismantlement accrual amounts based on a four-year average of the accruals related to the years between the dismantlement study reviews. We have reviewed TECO's "Generation Dismantling Model for FPSC" in detail, and have confirmed that the method TECO used in determining its proposed annual dismantlement accrual is consistent with Rules 25-6.04364(4) and (7), F.A.C.

a. Environmental component of the dismantlement costs for the solar facilities

The estimated base costs for dismantlement generally consist of four components: labor, material and equipment, disposal, and environmental costs. OPC witness Kollen recommended the Commission exclude at least the environmental component of the dismantlement costs on the solar generating assets. OPC Witness Kollen argued these costs are extremely speculative and are based on unsupported assumptions made by TECO witness Kopp regarding site abandonment and responsibility for site restoration. However, TECO witness Kopp refuted this argument, stating they assume all sites will be restored to a condition suitable for reuse for industrial development.

Witness Kopp quoted Rule 25-6.04364(2)(c), F.A.C., which defines "Dismantlement Costs" as "the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service." He then argued, persuasively, that OPC witness Kollen's suggestion to exclude the environmental component of the dismantlement costs on the solar generating assets, which includes site restoration costs, is both arbitrary and in conflict with this rule.

TECO witness Kopp testified that he had not seen a lease that placed the liability for removal of improvements and site restoration on anyone other than the solar facility owner. During cross examination, counsel for OPC pointed out that TECO witness Kopp did not review certain solar sites' land leases, so he did not know the environmental remediation requirements for those sites. Witness Kopp admitted that some of the leases were not available for review, but reiterated they typically include an appropriate level of site restoration in their assumptions, and any other requirements would typically be above and beyond that level, not less.

Witness Kopp further asserted that the absence of a land lease being available for review gives him no concern that he overestimated environmental or site restoration costs or included speculative costs. He explained:

> A land lease will likely only increase the need for environmental and site restoration costs beyond what is stated in the Florida Administrative Code and included in our estimates. This typically comes in the form of language that specifically requires the lessee to remove equipment and restore the sites to a

> defined condition, which simply reinforces the definition of "Dismantlement Costs" in the Florida Administrative Code as including site restoration.

As mentioned earlier, TECO witness Kopp testified that he has never seen a lease place the liability for removal of improvements and site restoration on anyone other than the solar facility owner. We are persuaded by witness Kopp's testimony, the Company will likely always incur some level of environmental-related cost to restore the solar site when the generation facility is dismantled. Witness Kopp also testified that site restoration requirements included in the leases are typically more stringent than the standard restoration requirement assumptions he and his team use in conducting a dismantlement study. Based on witness Kopp's testimony, we find that TECO's assumptions of site restoration/environmental remediation for dismantling the solar facilities are reasonable.

Counsel for FIPUG questioned whether TECO witness Kopp would make an adjustment to the estimate of the dismantlement cost in the scenario that the landowner does not want to remove the solar facility from the leasing land at the end of the lease. Witness Kopp testified that, while he had heard of it being an option, his studies all look "at the liability at the end of useful life of the facilities" and "that obligation is still typically on the utility at the end of life to take it out." Furthermore, witness Kopp disagreed with witness Kollen's statement that other utilities intentionally exclude dismantlement costs because of the uncertainties as to costs that may be incurred and whether the salvage income will exceed any such costs. He testified that:

> This is not an accurate representation of what is typical, based on my experience preparing dismantlement studies throughout the country and in particular in the state of Florida. First, every dismantlement study I have prepared, [. . .] have included site restoration costs. Second, utilities don't simply exclude these costs because of the uncertainties as to costs that may be incurred whether the salvage income will exceed any such costs. Instead, utilities typically hire an engineering firm to estimate the costs for the ultimate physical removal and disposal of plant and site restoration, minus any attendant gross salvage amount, upon final retirement of the site or unit from service, consistent with Florida Administrative Code. This allows a site specific cost estimate to be used to make a determination of how much salvage income will offset the costs, rather than simply speculating that they might exceed restoration costs. Lastly, even if some utilities in other parts of the country have gone with the speculative approach of intentionally excluding these costs because salvage income may exclude the costs, that is not consistent with Florida Administrative Code Rule 25-6.04364, and therefore not relevant.

We have reviewed TECO's 2023 dismantlement study in detail. The study does include the specifications of the assumed cost elements for dismantling each generating unit, including solar. For example, the tasks assumed for dismantling the Agrivoltaics Solar site include "removal depth of 3 feet below grade;" and the tasks assumed for dismantling the Alafia Solar site include "removal depth of 3 feet below grade" and "grading and reseeding the area inside the perimeter fencing." All of these are the environmental restoration activities.

Based on the foregoing, we find that TECO witness Kopp's inclusion of the environmental component in his assumptions for estimating the dismantlement costs of solar sites is appropriate and consistent with Rule 25-6.04364, F.A.C.

b. Application of Contingency

Rule 25-6.04364(2)(a), F.A.C., defines "Contingency Costs" as "[a] specific provision for unforeseeable elements of cost within the defined project scope." As in its prior dismantlement study filings, TECO controlled the application of contingency factors for calculating the dismantlement accrual. This allows the Company "easier study cost estimate comparisons and quicker scenario calculations."

A 15 percent contingency was utilized in TECO's 2023 dismantlement study. This contingency factor has three components: Engineering Scope, Cost Estimation, and Management Costs (indirect costs incurred to support vendor or non-vendor decommissioning work efforts), and each of these components was assigned a five percent contingency. TECO applied this 15 percent contingency factor to the cost estimates for Labor, Materials & Equipment and Environmental & Disposal, but this 15 percent contingency factor is not applied to the Salvage credits that resulted from the 2023 dismantlement study.

OPC witness Kollen considered the contingency costs TECO used to be "unsupported and unjustified." However, we disagree with that conclusion. TECO witness Kopp stated that the application of contingency is not only appropriate, but also standard industry practice. He provided very detailed reasons to support his statement, including the uncertainty associated with future work conditions, the scope of work, how the work will be performed, increases in costs, weather delays, discovery of materials or equipment not depicted on drawings, and unknown levels of environmental contamination. These considerations are appropriate to account for as contingency costs because the additional costs resulting from these items may be reasonably expected but the exact price impact is typically unknown or unspecified at the time. For those reasons, 1898 & Co. personnel "typically recommend and include a 20 percent contingency be added to the direct costs as reasonable and warranted based on the level of risk associated with the dismantlement projects." Furthermore, TECO witness Kopp noted although "the 15 percent contingency applied by the Company is less than [my] typical [20 percent] recommendation," it is nonetheless reasonable in light of TECO's specific circumstances and assets.

In light of the foregoing, we find that the application of a 15 percent contingency is appropriate. The contingency costs are consistent with the provisions of Rule 25-6.04364, F.A.C., and in line with prior Commission orders.[36]

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[36] Order Nos. PSC-08-0014-PAA-EI, issued January 4, 2008, in Docket No. 20070284-EI, *In re: Petition for approval of 2007 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company*; PSC-

c. Escalations to the current estimates of dismantlement costs

OPC witness Kollen proposed to "limit the dismantlement expense to costs escalated only through the test year and exclude all forecast growth in the dismantlement cost and expense beyond the end of the test year." TECO witness Chronister disagreed with OPC's proposal. He argued that "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." TECO witness Kopp further expounds that:

> The dismantlement costs should include "escalation rates" used in converting the current estimated dismantlement costs to future estimated dismantlement costs" as outlined in Rule 25-6.04364, [F.A.C.], Electric Utilities Dismantlement Studies. It is reasonable and appropriate that the 2023 costs I provided in my Dismantlement Study should be escalated to future years, to account for the impact of inflation, to put them in the year dollars in which they will be expended, and to most accurately reflect the actual costs to be incurred, consistent with Rule 25-6.04364, [F.A.C.]

TECO confirmed that the methodology and escalation rates it used in this study are the same as in prior filings.[37]

We find that forecast growth in the dismantlement cost and expense beyond the end of the test year should be appropriately included in the calculation of the dismantlement accrual pursuant to Rule 25-6.04364(4), F.A.C., which specified that the dismantlement annual accrual shall be calculated using the current cost estimates escalated to the expected dates of actual dismantlement.

d. Dismantlement cost resulting from TECO's 2023 dismantlement study

The dismantlement cost estimates in the current study are based on site-specific analysis. These cost estimates reflect an increase of approximately 86 percent from the cost estimates resulting from TECO's last dismantlement study as shown in Table 4. The key driver for the increase in cost is the plant additions of new solar sites since TECO's last dismantlement study. The Company also explained that the other major drivers for the cost increase are the addition of traveling screens and an organism return system at the Bayside Power Station site, and the increase of the Polk Power Station Site Cost Index.

12-0175-PAA-EI, issued April 3, 2012, in Docket No. 201101312-EI, *In re: Petition for approval of 2011 depreciation study and annual dismantlement accrual amounts by Tampa Electric Company*.

[37] Escalation rates are calculated using Moody's Analytics (Economy.com) forecasts. Historical information is provided for the years 2022 and prior. The needed forecast information is provided for the years 2023 to 2053. For the years 2054 and beyond, the same annual change percentage for year 2053 is carried forward. Since the cost estimates are provided in 2023 dollars, the dismantlement model initially escalates each unit's cost estimate into 2025 dollars to align with the study, which projects each unit's ending balance of reserve through December 31, 2024. Next, each unit's cost estimates are escalated to the projected retirement date to perform the present value calculations and averaging of the next four years' accrual results.

Table 4
Comparison of TECO's Estimates of Generation Plant Dismantlement Cost*

Account	2020 Study**	2023 Study***	Change ($)	Change (%)
Bayside Power Station	$14,575,850	$21,418,750	$6,842,900	46.9
Big Bend Power Station	$80,772,550	$86,859,500	$6,086,950	7.5
Polk Power Station	$15,229,450	$20,115,800	$4,886,350	32.1
MacDill Station		1,061,750	$1,061,750	-
Solar Sites	81,786,195	$228,872,135	$147,085,940	179.8
Total Surviving Assets	$192,364,045	$358,327,935	$165,963,890	86.3

* Including 15 percent contingency.
** In 2020 dollars.
*** In 2023 dollars.

e. TECO's annual accruals for dismantlement

TECO's currently approved annual accrual for dismantlement is $8,014,743. Its proposed annual accrual is $17,442,392 which represents an increase of approximately 117 percent. Apart from the aforementioned increased base costs, high escalation factors are also the major contributor to the large dismantlement annual accrual proposed. TECO argued:

> In a comparison of the instant 2023 study to the prior 2020 study inflation indices, the resulting compound multipliers (escalation factors) starting from year 2019, the year 2020 has minimal percentage differences between the actual and forecast. However, due to global inflationary impacts resulting from the pandemic and post pandemic economic environments, the annual projections for year 2021 and beyond are vastly higher in the instant 2023 study index. Increases in these compound multipliers (escalation factors) applied to the vendor cost estimates will yield increases in the dismantlement accruals.

As discussed in Issue 7 previously, we found a 35-year service life, instead of TECO's proposed 30-year service life, for solar plant to be appropriate. In responding to discovery requests from our staff, the Company provided a calculation of the annual dismantlement accrual using a 35-year service life for solar facilities. The result indicates a reduction of approximately $1.3 million in the accrual, compared to TECO's originally proposed amount. We adopt the reduced annual accrual for dismantling solar facilities so as to coincide with the 35-year service life for solar plant.

When addressing Issue 24, we order that the gasification equipment (Gasifier), heat recovery steam generator (HRSG), and steam turbine (ST) at Polk Unit 1 be retired in 2025. The associated cost recovery of the unrecovered investment and the un-accrued dismantlement cost are also addressed there. However, due to those decisions, we also remove here approximately $0.2 million to account for the 2025 annual dismantlement accrual pertaining to the Gasifier, HRSG, and ST at Polk Unit 1.

The escalation factors TECO used for deriving its proposed annual dismantlement accrual are based on Moody's Analytics' September 2023 publications. The Company provided, in July 2024, an update of the escalation factors based on the latest available Moody's inflation forecast. It also provided an updated annual accrual resulting from the utilization of the latest escalation factors, which reflect a reduction of approximately $0.1 million from TECO's originally proposed accrual. We find the use of these updated escalation factors reasonable for deriving the annual dismantlement accrual.

2. Conclusion

We hereby approve a total annual dismantlement accrual of $15,770,488 for TECO's generating facilities. This reflects our decisions regarding a 35-year service life for solar plants, the 2025 retirement of certain components of Polk Unit 1, and the updated escalation factors. Details of this dismantlement provision are depicted in Table 5.

Table 5
Dismantlement Accruals

GENERATION PLANT	CURRENT ACCRUAL (01/01/2022) $	COMPANY PROPOSED ACCRUAL (01/01/2025) $	COMPANY PROPOSED CHANGE IN ACCRUAL $	COMMISSSION APPROVED ACCRUAL* (01/01/2025) $	COMMISSSION APPROVED CHANGE IN ACCRUAL $
Bayside Common	270,547	399,464	128,917	383,764	113,217
Bayside Unit #1 (3xGT - HSRG - ST)	67,969	242,668	174,699	253,565	185,596
Bayside Unit #2 (4xGT - HSRG - ST)	107,666	340,207	232,541	353,001	245,335
Bayside GT's 3-6	(290)	9,288	9,578	16,619	16,909
Total Bayside Power Station	445,892	991,627	545,735	1,006,949	561,057
Big Bend Common (Handling)	1,756,377	1,578,811	(177,566)	1,588,579	(167,798)
Big Bend Unit #4	377,928	722,412	344,484	719,346	341,418
Big Bend GT 4	3,201	7,186	3,985	8,141	4,940
Big Bend GT's 5-6 (and Unit 1 CCST)	174,385	414,543	240,158	406,963	232,578
Total Big Bend Power Station	2,311,891	2,722,952	411,061	2,723,029	411,138
Polk Common (Handling)	430,877	535,436	104,559	515,762	84,885
Polk Unit #1 (Gasifier - GT - HRSG - ST)**	149,968	232,963	82,995	33,369	(116,599)
Polk 2-5 (4xGT - HRSG - ST)	99,409	202,186	102,777	218,655	119,246
Total Polk Power Station	680,254	970,585	290,331	767,786	87,532
MacDill Common	0	3,348	3,348	5,333	5,333
MacDill Unit 1 and 2	0	17,653	17,653	17,304	17,304
MacDill Unit 3 and 4	0	17,653	17,653	17,304	17,304
MacDill BESS	0	18,428	18,428	19,179	19,179
Total MacDill Station	0	57,082	57,082	59,120	59,120
Tampa International Solar	36,807	40,893	4,086	34,750	(2,057)
Big Bend Solar	213,003	236,966	23,963	202,213	(10,790)
Legoland Solar	8,161	10,303	2,142	8,644	483
Balm Solar	725,322	783,385	58,063	690,245	(35,077)
Bonnie Mine Solar	289,424	345,622	56,198	304,408	14,984
Grange Hall Solar	431,870	518,692	86,822	454,561	22,691
Lake Hancock Solar	337,632	408,257	70,625	358,422	20,790
Lithia Solar	524,578	638,608	114,030	561,722	37,144
Little Manatee River Solar	536,440	645,580	109,140	571,438	34,998
Payne Creek Solar	535,696	653,202	117,506	570,497	34,801
Peace Creek Solar	373,933	446,832	72,899	393,079	19,146
Wimauma Solar	563,840	743,515	179,675	655,051	91,211
Agrivoltaics Solar	0	6,020	6,020	5,328	5,328
Alafia Solar	0	432,587	432,587	383,577	383,577
Big Bend Floating Solar	0	2,220	2,220	2,291	2,291
Big Bend Solar Phase 2	0	75,106	75,106	65,836	65,836
Brewster Solar	0	259,621	259,621	231,529	231,529
Bull Frog Creek Solar	0	483,898	483,898	429,000	429,000
Cotton Mouth Ranch Solar	0	504,338	504,338	447,000	447,000
Durrance Solar	0	563,300	563,300	497,053	497,053
Eastern PVS+ES Solar	0	4,723	4,723	4,277	4,277
English Creek Solar	0	447,934	447,934	395,952	395,952
Florida Aquarium Pavilion Solar	0	565	565	507	507
Future Property 1 Solar	0	505,775	505,775	450,602	450,602
Future Property 2 Solar	0	505,775	505,775	450,602	450,602
Jamison Solar	0	521,734	521,734	466,316	466,316
Juniper Solar	0	537,349	537,349	477,107	477,107
Lake Mabel Solar	0	524,568	524,568	469,631	469,631
Laurel Oaks Solar	0	411,730	411,730	362,966	362,966
Magnolia Solar	0	629,160	629,160	555,444	555,444
Mountain View Solar	0	364,511	364,511	320,158	320,158
Riverside Solar	0	447,377	447,377	393,398	393,398
Total Solar Sites***	4,576,706	12,700,146	8,123,440	11,213,604	6,636,898
Total Dismantlement Accrual	8,014,743	17,442,392	9,427,649	15,770,488	7,755,745

*The accrual amount incorporates TECO's proposed updated escalation factors to reflect the latest inflation forecast.
**The accrual amount reflects the ordered 2025 retirement of certain components at Polk Unit 1, calculated by using "TECO's 2023 Generation Dismantlement Model for FPSC."
***The accrual for each solar site reflects a 35-year service life, calculated by using "TECO's 2023 Generation Dismantlement Model for FPSC."

H. Dismantlement Reserve Measures (Issue 12)

1. Analysis

TECO's estimate of the total amount of dismantlement cost is approximately $358.3 million, while its total amount of dismantlement reserve, as of December 31, 2024, is $113.6 million. This represents a total reserve imbalance of approximately negative $244.7 million (deficit) in the dismantlement reserve.

TECO witness Chronister proposed that all of the dismantlement reserve imbalances (surpluses and deficiencies), if any, should be resolved over the remaining life of the related assets. This is consistent with OPC's position that all imbalances should be flowed back over the useful lives of the assets. Other intervenors who took a position, adopted OPC's position, except FL Rising/LULAC whose position does not address the corrective measure for the reserve imbalances. Furthermore, neither the Company nor any of the intervenors have proposed alternative measures to correct the reserve imbalances. We therefore agree that all reserve imbalances should be resolved over the remaining life of the related assets.

2. Conclusion

The $244.7 million deficit in dismantlement reserve shall be resolved over the remaining service lives of the related assets. No other corrective dismantlement reserve measures are needed.

V. Rate Base

In this section we discuss the various components that determine the 2025 Rate Base. These issues were identified as numbers 13 through 32 in the Prehearing Order, and cover topics including, among others, Future Environmental Compliance (Issue 14), Customer Experience Enhancement (Issue 16), Solar Projects (Issue 18), Corporate Headquarters (Issue 21), as well as the appropriate amounts for Plant in Service (Issue 25), Construction Work In Progress (Issue 27), and Property Held for Future Use (Issue 28).

A. Removal of Non-Utility Rate Base (Issue 13)

1. Analysis and Conclusion

FL Rising/LULAC opposed the removal of certain projects from Plant in Service, Accumulated Depreciation, and Working Capital., but those parties do not specifically address non-utility activities. TECO has provided proof of the removal of non-utility activities from these accounts through TECO witness Chronister's direct testimony and MFR Schedules B-1, B-2, B-6, and B-7. Because TECO has made the appropriate adjustments to remove all non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital, we find that no further adjustments are necessary.

B. Future Environmental Compliance Project (Issue 14)

1. Analysis

TECO sought to recover certain costs associated with a Carbon Capture and Storage (CCS) evaluation as part of a Future Environmental Compliance project. TECO witness Stryker explained that CCS is a process where carbon dioxide is absorbed from the exhaust gas of a power plant and then concentrated and compressed for storage deep in the earth. TECO asserts CCS technology can remove approximately 90 percent of carbon emissions from a power plant. The Company is evaluating CCS technology now because of a proposed rule by the U.S. Environmental Protection Agency (EPA) and because of the availability of federal financial support. The EPA Rule would impose standards for greenhouse gas emissions for certain fossil fuel-fired electric generating units. However, this year the EPA announced that natural gas-based units would not be covered by the proposed rule and a separate rule limiting emissions from natural gas-fired units would be issued.

TECO received approximately $98.4 million from the U.S. Department of Energy in the form of three separate funding grants for the following items: (1) front-end engineering study; (2) evaluation of storage and transportation component; (3) and the Carbon Safe Program, which is a detailed geological characterization of the potential storage facility. The funds can only be used for TECO's CCS evaluation project. Witness Stryker testified that the total cost of the CCS evaluation is estimated to be $126.5 million with TECO's portion totaling approximately $28.1 million. Of the $28.1 million, $18.2 million is capital expense and is included in the 2025 test year. However, TECO is not seeking recovery of the estimated $9.9 million of O&M expense in this proceeding. The CCS evaluation should be completed by the end of 2025.

FL Rising/LULAC witness Rábago recommended that we disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented benefit-cost analysis (BCA). He further argued that TECO's current approach to developing major capital projects relies solely on management discretion and a cumulative present value of revenue requirements (CPVRR) approach that lacks transparency and objectivity, and that ignores cost-effective alternatives that may offer better, more affordable outcomes. FL Rising/LULAC believe that without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, this Commission has no way of knowing whether TECO's spending proposals will result in rates that are fair, just, and reasonable. In summary, FL Rising/LULAC do not believe TECO has met its burden of proof for this project.

Sierra Club also opposed this project. Sierra Club witness Glick testified that TECO has not performed an analysis comparing the costs of CCS at Polk 1 with the cost of simply retiring the unit. Moreover, witness Glick argued that TECO has not clearly stated what its CCS plans are, nor has it evaluated the costs of CCS in detail. Witness Glick further testified that CCS does not justify the cost and risks it imposes on ratepayers. According to Sierra Club, TECO would be better off retiring the unused equipment and using its capital to build out commercially available options such as solar photovoltaic and battery energy storage systems.

2. Conclusion

We share some of the concerns raised by the intervenors and find that TECO has not met its evidentiary burden for this project. The first reason for denying this project is because the EPA Rule has not been finalized and there is no guarantee it ever will be. Whether the EPA Rule is adopted and what its final requirements ultimately will be are both unknown. Therefore, it is premature to burden ratepayers with speculative costs associated with proposed regulation that may not even come into being. This alone constitutes sufficient basis to deny the Future Environmental Compliance Project.

Furthermore, despite TECO witness Stryker describing CCS technology as well-proven, there have been a number of recent failures of CCS projects across the United States. The biggest risk of CCS is cost overruns according to Sierra Club witness Glick. For example, "Southern Company's attempt to construct an [Integrated Gasification Combined Cycle] unit with CCS plant at Kemper resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion) before the Mississippi Public Service Commission ultimately pulled the plug on the project" in 2017. Additionally, in 2008 the Virginia State Corporation Commission refused to make ratepayers bear costs associated with CCS due in part to uncertainties surrounding the technology. For all of these reasons, we deny the proposed CCS project.

TECO's proposed Future Environmental Compliance Project, with a capital cost of $18.2 million, shall be excluded from the 2025 projected test year. We find the Company has not met its evidentiary burden given uncertainties surrounding the technology and uncertainty regarding whether the EPA Rule will be finalized.

C. Research and Development Project (Issue 15)

1. Analysis

TECO witness Striker testified that the Company is currently pursuing two research and development (R&D) projects to be included in the 2025 projected test year. These projects are the Long Duration Energy Storage (LDES) project and the Florida Conservation and Technology Center (FCTC) Microgrid project. TECO witness Striker asserted that both projects use emerging technologies that will be used in the future. TECO is requesting recovery of $7.1 million in capital costs for both R&D projects in the projected test year.

No intervenor provided testimony regarding these projects. However, in their briefs, FL Rising/LULAC and FRF disagreed with the inclusion of the R&D projects in the 2025 projected test year, both arguing that TECO had not met its burden to show the necessity of the projects.

a. Long Duration Energy Storage Project

The LDES project is a pilot program intended to explore alternative flow battery technology that will be capable of storing energy at a longer duration than the lithium-ion battery technology typically utilized. TECO witness Striker affirmed that the cost-effectiveness of lithium-ion batteries diminishes at longer storage durations and the LDES will allow TECO to evaluate flow battery technology as a suitable lithium-ion battery alternative. The witness further affirmed that the smaller R&D project will allow TECO to gain a better understanding of the flow batteries longer-term storage capabilities, challenges, and costs that would be applied to future projects. TECO also claimed that it evaluated alternative long duration battery technologies, such as liquid air energy storage, but the promptness of implementing the chosen battery technology and the suitability of the battery technology for smaller scale construction guided the Company towards the chosen flow battery. The LDES project will be interconnected at the Big Bend II Solar substation and will be capable of providing 0.78 MW of energy on TECO's system. The LDES project is anticipated to be operational in mid-2025. TECO is requesting $4,227,020 of capital costs in base rates for the project through 2025.

b. Florida Conservation and Technology Center Microgrid Project

The FCTC Microgrid project is a pilot program that would adapt both existing FCTC electric load and nearby existing solar facilities on TECO property into a microgrid with the capability of operating independently from TECO's electrical grid. This would be accomplished with the addition of an energy storage system, microgrid control system, power conversion systems, and other equipment to enable the existing solar facilities to be interconnected and operated in a local microgrid system. TECO witness Striker stated that the microgrid project would allow TECO to evaluate the costs and benefits associated with enabling customers to construct and operate customer-owned distributed energy resources.

The proposed pilot program shares some similarities with TECO's previously approved direct-current (DC) Microgrid pilot. However, while the DC Microgrid pilot's objective was to demonstrate the ability of TECO to manage high-level renewable energy at residential homes, the FCTC Microgrid would demonstrate the ability of TECO to serve the microgrid load exclusively from existing renewable energy and develop a repeatable process for implementing microgrid projects at other locations. TECO witness Stryker further distinguished the two projects when he indicated that the DC Microgrid pilot project was comprised of integrating a large number of smaller distributed renewable resources at individual residences, in comparison to the proposed FCTC Microgrid project that consists of integrating a smaller number of centralized renewable resources interconnected at the distribution level. According to the Company, these distinctions led to the DC Microgrid concept being more suitable for concurrent installation during construction of new residential communities and the FCTC Microgrid concept being more suitable for being retrofitted to existing renewable systems.

The FCTC Microgrid is anticipated to be operational by the end of 2026. As part of the 2025 projected test year, TECO requested to include $2,846,972 of capital costs in base rates for the project through 2026. However, though the project's in-service date is in 2026, the Company has only provided costs through 2025. As discussed later within this order, we allow a subsequent year adjustment (SYA) for the incremental costs associated with the annualization of projects that are in-service during the projected test year. As noted above, the FCTC Microgrid project has an in-service date of 2026 (which falls outside of the 2025 projected test year). In traditional ratemaking, TECO would still be able to construct the facilities if existing rates were sufficient or request a limited proceeding closer to the in-service date of the project. Because the FCTC Microgrid project will not be in-service during the projected test year and because TECO has not demonstrated a definitive reliability need associated with this project, we decline recovery at this time.

2. Conclusion

We approve the inclusion of TECO's proposed LDES project, with a capital cost of approximately $4.2 million, in the projected test year. This project allows TECO to explore alternative battery technologies which is beneficial because it can lead to establishing longer duration utility scale battery energy storage. Furthermore, the LDES project benefits customers by providing cost-effective alternatives that bolster TECO's renewable resource portfolio.

At this time, however, we deny inclusion of the FCTC Microgrid project, with a capital cost of $2,846,972, in the projected test year. We do so for two reasons. First, the project will not be in-service until 2026. TECO sought recovery for this project in the 2025 projected test year. Second, TECO has not demonstrated a reliability need for this project.

D. Customer Experience Enhancement Project (Issue 16)

1. Analysis

TECO's proposed Customer Experience Enhancement Projects cover a broad range of capital investments that focus on three main areas: Customer Digitalization, Operational Efficiency, and Optional Customer Programs. The purpose of these projects is to streamline processes for greater efficiency and responsiveness and invest in staff training to better understand and anticipate customer needs. In support of these projects, TECO witness Sparkman testified that the Company intends to adopt a more personalized approach to service, using data analytics to gain insights into customer preferences, and using technology to enhance interaction and service delivery.

The Customer Digitalization projects are intended to enhance TECO's digital platforms to provide customers with a convenient and efficient way to access services, information, and support. An example project is the customer's Interactive Bill, which will have more granular usage data, personalized insights based on usage and patterns, additional weather details, and comparisons to other customers with similar sized homes. TECO projected that the Customer Digitalization projects will include $4.4 million of capital costs and $0.174 million of annual O&M expenses.

The Operational Efficiency projects are intended to enhance the operational efficiency of TECO's organization with the potential use of artificial intelligence and machine learning, advanced data analytics, and customer segmentation. These projects are aimed to help TECO proactively recognize specific customer needs and ensure a more efficient and responsive service experience. For example, through the use of artificial intelligence, TECO would be able to detect customer consumption patterns and proactively present energy management solutions. TECO projected that the Operational Efficiency projects will include $4.1 million in capital costs and $1.4 million of annual O&M expenses.

The Optional Customer Programs provide customers more choice and flexibility in how they use TECO's services. The programs are intended to cater to the diverse needs and preferences of the customer base, and therefore, enhance the customer's overall experience and satisfaction with TECO's services. The Optional Customer Programs include TECO's Drive Smart electric vehicle charging pilot, investments to improve the administration of existing customer programs such as net metering, and investments in the design of additional customer programs and/or pilots to service customers who have renewable energy goals such as rooftop solar. TECO projected that the Optional Customer Programs will include $4.9 million in capital costs with no O&M expenses.

TECO witness Sparkman testified that a primary driver for these projects is customer demand. TECO indicated that, based on research, customers have high expectations and expect the same level of service and offerings that they receive from other companies, including how they view and pay their bills, receive communications, access their accounts, answer questions, and resolve problems. Furthermore, TECO explained that delaying the Customer Experience Enhancement Projects would prohibit TECO from providing customer enhancements that may result in customer dissatisfaction.

During the hearing, however, OPC questioned TECO witness Sparkman on its customer surveys. She testified that TECO conducts monthly surveys regarding customer experience on a volunteer group of residential customers, known as the Power Panel. The Power Panel survey results indicated that 86 percent of customers were not willing to pay additional money for digital service options and that digital offerings had the lowest percentage of importance to customers out of a list of several options. OPC argued that the "Optional Customer Programs" are unsupported. OPC asserted that all of TECO's customers would be charged for these programs; however, not all customers would benefit from all these programs.

While not specifically addressing these projects, FL Rising/LULAC witness Rábago recommended that the Commission disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, FL Rising/LULAC assert that this Commission has no way of knowing whether TECO's spending proposals will result in rates that are fair, just, and reasonable.

In response, TECO explained that the cost benefit analysis for these projects includes a capital and O&M costs assessment, a benefit assessment, a determination of the internal rate of return and payback period, and a thorough risk analysis. The benefit assessment includes financial, strategic, alignment, customer value, best practices, and other organizational benefits. Although we find TECO's response sufficient to explain the Company's costs and benefits, we do not find it adequately addressed customer impact concerns.

2. Conclusion

We find there is no need for these projects at this time. Despite TECO witness Sparkman's assertion to the contrary, the customer survey evidence reveals that the vast majority of customers are unwilling to pay for these enhancements. Furthermore, not one customer testified during the service hearings that these enhancements were wanted or needed. Nor were there any customer comments that indicated a need for these projects. Rather, as discussed previously under Issue 4, the overwhelming majority of customer's comments addressed the potential rate increase. Finally, these projects are not needed in order for TECO to provide reliable service to its customers. Therefore, we exclude the capital costs of approximately $13.4 million and the O&M costs of approximately $1.6 million for the Customer Experience Enhancement projects from the test year.

E. Information Technology Capital Projects (Issue 17)

1. Analysis

TECO witness Heck testified that the Company plans to invest $22.9 million in 2025 on six different Information Technology (IT) projects.

First, TECO witness Heck described the ServiceNow project as a cloud-based IT Service Management and IT Operations Management platform. It allows the IT department to automate many of its processes, such as inventory management, routing of service requests, commissioning and decommissioning of assets and compliance and reporting functions. This platform will enable the IT department to handle increasing workloads without increasing staff, improve IT system reliability, and improve cybersecurity and regulatory controls. This project is a multi-year project schedule for 2024 and 2025. The cost will include $0.4 million in capital costs and approximately $0.6 million in O&M costs for 2025.

Second, the IT Infrastructure Upgrades project is for replacing/upgrading end of life data center hardware and software including servers, network equipment, data storage equipment, databases, and operating systems. The IT department will make purchases throughout each year to support new applications. These investments ensure that TECO's IT infrastructure is reliable and is supported by the providing vendors. The cost will include $9.5 million in capital costs in 2025.

Third, the Cybersecurity project implements new technologies and processes to strengthen the Company's security and compliance position. The projects are based on the National Institute of Standards and Technology, Cybersecurity Framework 2.0, and Control Objectives for Information and related Technology Framework's corporate policies and standards. The cost will include $7.2 million in capital costs and approximately $0.6 million in O&M costs for 2025.

Fourth, the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Enhancements and Upgrades project protects TECO's critical generation, transmission, distribution, and technology assets from cyber criminals. It includes the upgrade of software used for management of intelligent devices located in the transmission and distribution substations, which is required by NERC. This project will ensure that TECO remains in compliance with current NERC CIP standards and effectively protects the Company's electric grid critical infrastructure. The cost will include $1.1 million in capital costs for 2025.

Fifth, the SAP Enterprise Resource Planning (ERP) and Customer Systems are integrated applications that provide corporate and customer functionally including accounting, financial consolidation and reporting, financial analytics and planning, accounts payable/receivable, payroll, employee information database, recruiting, supply chain and inventory management, customer information database, customer billing, and customer service. The upgrades and enhancements will keep TECO's SAP ERP and Customer System up to date, secure, and ensure that it retains support. The cost will include $3.3 million in capital costs for 2025.

Sixth, the Non-ERP Corporate applications are for corporate functions and processes that include contract management, document/records management, employee websites, employee collaboration and productivity, process automation, project management, process controls, compliance, legal, real estate, and safety. Upgrading and enhancing these applications will ensure that TECO's team members in those areas have the tools necessary to work effectively, efficiently, and securely. The cost will include $1.4 million in capital costs for 2025.

No intervenor specifically addressed these projects in testimony. However, FL Rising/LULAC witness Rábago recommended that the Commission should disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, FL Rising/LULAC assert that this Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable.

Through discovery, TECO explained that the analysis for these projects includes cost-effectiveness, lifecycle analysis of the current solution, a market analysis of available solutions, cybersecurity health assessments, as well as the reliability, resiliency, and supportability of the existing solution. In addition, projects are evaluated during the annual budgeting process and determined to be necessary to improve the customer experience, providing a more modern intuitive interface, increase functionality, replace aging application software, reduce cybersecurity risks, and improve the quality of data. The IT Department follows a formal bidding process to ensure that goods and services are unbiased, consistent, and objective procurement process that leads to the lowest reasonable cost while maintaining necessary quality of product and effectiveness of the project.

When asked if any of the project could be delayed, TECO responded that, if the projects were delayed, the IT systems would no longer be supported by the vendor. In addition, the systems would cause customer service/transactions (such as billing, outage reporting, answering customer calls) and critical business operations (such as financial reporting, payroll, accounts payable, crew work-order for customer support, crew work-orders for asset management, and grid balancing) to be delayed or unavailable and create a need to rely on manual processes. The IT systems will not receive normal support and enhancement upgrades, causing business process improvements to be delayed, driving up manual work and O&M costs. This would also cause cybersecurity vulnerabilities to TECO's customer data, business operations, and critical infrastructure at risk.

When asked about Cybersecurity Insurance, TECO witness Heck confirmed that TECO does have Cybersecurity Insurance. He explained that the insurance would cover a portion of cybersecurity criminals getting into TECO's network and causing harm to the Company. The insurance also covers a portion of ransomware payments. TECO's cyber risks are audited by the insurer to verify TECO is mitigating the risks.

2. Conclusion

We find TECO witness Heck's testimony about these six IT projects credible and persuasive. Furthermore, his testimony on this issue was uncontroverted. TECO has provided us with detailed descriptions of its proposed projects and sufficient bases for why they are needed. We are particularly persuaded by the justification that replacing hardware and software that is at the end of its life and no longer supportable is prudent. Moreover, improving cybersecurity of its systems and protecting customer information is of paramount concern here. Therefore, the proposed Information Technology Capital Projects, with a capital cost of $22.9 million, shall be included in the 2025 projected test year without any adjustments.

F. Solar Projects (Issue 18)

1. Analysis

TECO proposed adding 246.6 MW of solar capacity by the end of 2025. The 2024 solar projects consist of the English Creek and Bullfrog Creek solar projects and represent a total of 97.5 MW of solar capacity, both with in-service dates of December 2024. The 2025 solar projects consist of the Duette and Cottonmouth solar projects and represent a total of 149 MW of solar capacity, both with in-service dates in December 2025. TECO witness Aponte testified that the 2024 and 2025 solar projects have projected installed costs of approximately $144.9 million and $214.4 million, respectively. During the hearing, TECO witness Stryker clarified that the Duette project had been renamed to "Long Branch."

TECO witness Stryker explained that the proposed solar facilities are needed to provide TECO customers with cost-effective renewable energy that would circumvent fuel price volatility. He further explained that the projects were not immediately necessary on the basis of TECO's capacity reserve margin, but would provide economic value that would be decreased if the projects were delayed. He clarified that TECO has assembled a team of employees and contractors experienced with construction of solar projects that would be lost if the projects were delayed and would result in increased costs in order to be regained later. Additionally, TECO witness Stryker explained that the passage of the IRA is providing production tax credits (PTCs) for the proposed solar facilities that would be deferred if the solar projects were delayed.

TECO witness Aponte testified that the 2024 and 2025 solar projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the solar facilities and the omission of the solar facilities. This comparison was used to determine the system CPVRR. The conclusion of the analyses determined that the addition of the 2024 and 2025 solar projects would result in a CPVRR savings for customers of $34 million and $52.6 million, respectively. The majority of the identified CPVRR savings are from reduced fuel costs and PTCs that the projects would provide. There are no savings associated with system capacity from installing these projects. On a CPVRR basis, the 2024 and 2025 solar projects are projected to be cost-effective in 2033 and 2035, respectively.

FIPUG witness Ly asserted that the cost-effectiveness tests performed by the Company did not provide a robust evaluation of the projects under various capital cost and fuel cost assumptions. We disagree. TECO witness Aponte testified that the Company had in fact performed sensitivity analysis for both fuel cost assumption and capital cost assumptions. For example, he explained that CPVRR analysis was performed using low and high fuel price forecasts for the solar projects which resulted in CPVRR savings under both fuel price scenarios. TECO witness Aponte further testified that TECO performed sensitivity analysis for capital cost assumptions during the initial planning of the project, which resulted in savings even with a 10 percent increase in capital cost assumption. We thus find that TECO performed a comprehensive evaluation of the cost-effectiveness of the solar projects.

FIPUG witness Ly also testified the PTCs associated with the solar facilities are reliant on the solar facilities maintaining a 26 percent annual capacity factor over the first 10 years of operation and should be subject to a minimum capacity factor. However, TECO witness Aponte rebutted FIPUG's claim because the initial cost-effectiveness analysis of the solar projects already included conservative assumptions by accounting for a 0.4 percent projected capacity degradation factor per year and a lower capacity factor during the first full year of operation that would increase by 1 percent annually (until reaching the designed capacity factor by year five). In addition, TECO witness Aponte indicated that using the base fuel price scenario, which excludes the annually increased capacity factor, results in increased CPVRR savings of $36.3 million for customers. We find that the inclusion of these conservative assumptions show that the cost-effectiveness of the solar projects are not conditioned on maintaining a 26 percent annual capacity factor. These assumptions provide additional, supportive data in the evaluation of the proposed solar units' PTC benefits and ability to reliably meet projected capacity factors.

Furthermore, TECO witness Stryker testified that it would be inappropriate to apply a performance standard to a subset of one utility's generating assets. He stated that if a performance standard were to be applied to TECO's proposed solar units, that it would be more appropriate for this Commission to develop a universal performance standard that would apply generally to all Florida public electric utilities' solar units. We agree that it would be inappropriate based on the record before us to apply performance standards only to TECO's solar units and thus decline FIPUG's invitation to do so.

2. Conclusion

For the reasons stated herein, we find the proposed 2024 and 2025 solar projects will provide cost-effective energy for TECO's system. These solar projects will provide savings for ratepayers and bolster TECO's renewable energy portfolio while providing a minimal reliability benefit. We therefore approve inclusion of these projects, with a combined capital cost of approximately $359.1 million, in the 2025 projected test year with no adjustments.

G. Grid Reliability & Resilience Projects (Issue 19)

1. Analysis

TECO's requested Grid Reliability and Resilience (GRR) Projects consist of over 40 interdependent projects that include telecommunications, control center operational technology, back-office information technology, distributed energy resources, and substations. When complete, these projects will create a "system of systems" to benefit customers. TECO's goal is to complete all component projects by the end of 2030. These projects are aggregated, which TECO witness Whitworth believes will result in more efficient capital spending and enhanced functionality as the system elements are deployed. TECO witness Whitworth argued that these projects are necessary to replace obsolete systems and equipment that have reached end of life as well as meet customer demands for greater reliability, greater access to data, and to adapt to changes in how customers consume energy. In addition, these projects will result in quantifiable benefits in terms of reliability and avoided capital and O&M expense. TECO witness Whitworth testified that TECO's System Average Interruption Duration Index will reduce 30 minutes per year, Momentary Average Interruption Event Frequency Index will reduce to near zero, 30 million customer minutes of interruption will be avoided, and Customers Experiencing More Than Five Interruptions will reduce to near zero by 2031.

TECO witness Lukcic testified that TECO is proposing to include 12 projects in rate base for 2025 and three projects in the subsequent year adjustments. Table 6 lists the 12 projects for 2025 with the associated capital amounts. In addition, there are no O&M costs for these projects. Each of these projects, excluding Data Analytics Platform (DAP), are a continuation of work that TECO performed in 2022 through 2024.

Table 6
2025 GRR Projects

Projects	**Capital Cost**
1.Significant GRR Projects	$65,871,743
2. DAP	$18,075,079
3. Blanket – Lighting	$16,069,585
4. Operations Technology Application	$11,312,970
5. Other	$4,188,739
6. Blanket – Meter	$3,867,678
7. Electric Delivery Capital Maintenance/Improvement	$2,900,685

8. Meter Operations	$2,815,381
9. Advanced Metering Infrastructure	$2,038,651
10. ES Capital Maintenance/Improvement	$665,000
11. Lighting – Growth	$550,000
12. Light – Operations	$500,000
Total Cost in 2025	$128,855,509

a. Significant GRR Projects

Witness Lukcic explained that the GRR Projects address changes to the grid, including digitalization, decentralization, and decarbonization, along with increases in distributed generation (e.g., rooftop solar), use of electric vehicles, and growth in other distributed technologies such as battery storage. These projects will enable TECO to meet rising customer demand and enhance reliability by reducing the frequency, duration, and impact of outages. The GRR Projects are comprised of the following projects:

- Control Systems Operations Technology, which monitors and controls assets in the field;
- Back Office IT, which includes system implementation, software licensing, interfaces, data migration, and new configurations for back-office systems such as Geographic Information System and Work Management System;
- Field Devices, which involves deploying a variety of detection and operational devices to provide greater monitoring and control;
- Substation, which modernizes and replaces obsolete and end-of-life equipment to prepare for bi-directional power flows, including system protection and optimization of circuit level action;
- Distributed Energy Resources (DER) Infrastructure, which implements monitoring and controls that will coordinate DER and electric vehicles on the system; and
- Grid Communication Network Project, which addresses the need for data transmission and communication through construction of a Private Cellular Network.

b. Data Analytics Platform

DAP is a software operating system that allows TECO to collect and analyze data including transformer loading, events, and alarms as testified by witness Lukcic. DAP also identifies proactive substation transformer maintenance and replacements. Witness Lukcic explained that TECO uses the data to proactively reduce outages. DAP provides real-time customer data to the call center to help Customer Service Professionals respond to customers' calls. This is a new project.

c. Blanket – Lighting

The Blanket – Lighting project includes purchase and replacement of streetlights. Witness Lukcic testified that the purchases are needed to accommodate growth, respond to customer requests, and ensure continued support of the lighting network. The benefits of this project include meeting customer demand, public safety, reliability, and integration with smart city technology.

d. Operations Technology Application

TECO witness Lukcic testified that the Operations Technology Application project enables operational control of TECO's power plants and grid systems, network communication and management of operational data, and collection and analysis of sensor data, which helps TECO understand the condition and performance of the grid. The project also facilitates the maintenance and operation of the grid assets.

e. Other

The Other projects category includes various telecom and analytics projects. Included in these projects are LED Lightning Conversion Initiative, 15 Telecom growth projects, 11 Telecom projects, 6 Telecom Operations projects, and 9 upgrade and enhance back-office system projects. TECO witness Lukcic explained these projects are needed to support routine customer growth and operations. The benefits include the ability to support continued reliability and standard field operations.

f. Blanket – Meter

The Blanket – Meter projects include the purchase and replacement of failed electric meters as explained by witness Lukcic. The purchases are necessary to accommodate growth and provide continued support for the communication network. The meters will improve networking capabilities to provide faster and more reliable responses to customers for switching and data analysis.

g. Electric Delivery Capital Maintenance/Improvement

Witness Lukcic testified that the Electric Delivery Capital Maintenance/Improvement project proactively addresses TECO's identified risk assets from TECO's asset class mitigation plan. When TECO identifies a common risk of failure in many similar or identical assets, the Company develops a mitigation plan. This will allow work for a group of assets by bundling and bidding of work, which will obtain a low reasonable cost. The project will improve reliability by mitigating failures and provide reduced costs associated with equipment replacement. Proactively replacing equipment reduces costs compared to reactively replacing equipment.

h. Meter Operations

The Meter Operations project is a meter firmware upgrade. Witness Lukcic explained that the firmware is a set of embedded software instructions that govern the operation of a metering device. This includes managing the collection, processing, and transmission of data such as electricity consumption. The firmware will enhance the customers' remote monitoring and management and TECO's ability to swiftly address issues and minimize downtime without physically accessing the meters.

i. Advanced Metering Infrastructure

The Advanced Metering Infrastructure (AMI) project includes advanced smart meter system, communication infrastructure, and data management systems upgrades. TECO completed the conversion of the Advanced Meter Reading in 2021 and has continued to enhance the AMI system since that time. The AMI system includes advanced smart meters, communications infrastructure, and data management systems. The smart meters collect near real-time data that allows the customers to manage their electric use through daily and monthly usage graphs. The meters also provide the customer with information regarding how the weather will affect their bills.

j. Energy Supply Capital Maintenance/Improvement

Witness Lukcic explained that the Energy Supply Capital Maintenance/Improvement project facilitates monitoring the condition and performance of TECO's generation assets and allows TECO to proactively replace components before failure, identify opportunities to improve unit efficiency and performance, and improve safety. The project will ensure proactive mitigation of failures, which will improve reliability, and proactive procurement and planning of capital work, which will reduce cost.

k. Lighting – Growth

TECO's requested Lighting – Growth project is designed to satisfy customer lighting service requests such as solar powered or decorative lightning. The Lightning – Growth project seeks to acquire existing lighting systems, special projects, and new lighting products as the Blanket – Lighting projects fulfills inbound lighting service requests and addresses the long-term maintenance needs of regulated business.

l. Lighting – Operation

The Lighting – Operation project is the installation of intelligent lighting systems to fulfill customer requests, as explained by witness Lukcic. The smart lighting fixtures enhance safety and security, provides data insights and analytics, and offers customization and flexibility to meet community needs.

Having explained the GRR Projects and their benefits, we now turn to the arguments raised by intervenors. OPC witness Mara argued that the type of programs in the GRR Projects are planned replacements of existing and obsolete facilities. Further, these types of programs are normally included in the annual budget and would be accounted for in a representative test year. However, increases in the test year costs for these routine types of activities unnecessarily increases costs for customers and should be scrutinized for imprudent spending. As a result, OPC does not believe the GRR Projects should be approved for inclusion in the 2025 test year.

While not specifically addressing these projects, FL Rising/LULAC witness Rábago recommended that the Commission should disapprove any capital spending project of

$1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. Without BCAs to analyze alternatives and inform consideration of proposals submitted for approval, FL Rising/LULAC assert that this Commission has no way of knowing whether TECO spending proposals will result in rates that are fair, just, and reasonable. Additionally, witness Rábago recommended that the Commission should disapprove most, if not all, of the requested rate recovery for the GRR projects, as he believes it is additional spending by TECO that is unjustified and unreasonable. In summary, FL Rising/LULAC did not believe TECO has met its burden of proof for this project.

TECO witness Lukcic rebutted OPC witness Mara by testifying that the GRR Projects build on TECO's existing grid modernization strategy and will provide new and enhanced functionality across each of the investments. He further argued that none of the projects are considered routine maintenance or equipment replacements. Instead, each project provides new or enhanced functionality to meet customer expectations and provide smart grid benefits. Further, the GRR Projects are necessary to replace obsolete systems and equipment, as well as meet customer demands for greater reliability, greater access to data, and to adapt to changes in how customers consume energy.

2. Conclusion

We find TECO witness Lukcic's testimony about the GRR Projects credible and persuasive. The GRR projects are not routine maintenance. In addition, TECO witness Whitworth testified that replacing obsolete equipment does not always constitute normal activities for a utility, especially here where some assets are replaced because they are not compatible with the communication technology. We are persuaded by the testimony and evidence presented by TECO that technology is evolving and its grid needs to adapt in order to best serve its customers. For example, with the GRR projects, TECO will have the technology to be able to pinpoint precisely where the outage is and dispatch troubleshooters and repair workers to a very specific location. Witness Whitworth testified the technology will be able to detect grid outages and automatically restore as many customers as possible prior to human intervention. We recognize the benefits that the GRR Projects will bring to customers in the form of reliability, but also the benefits for TECO employees, such as safety. For example, TECO employees will be able to isolate the system and safely remove any hazards.

TECO witness Lukcic also argues that by aggregating these projects under a common heading, the overall approach is better coordinated and results in a more efficient spending of capital. This also results in considerably more allowance for funds used during construction (AFUDC). Witness Lukcic explained that TECO found the most cost-effective way to deploy the projects, along with providing the maximum value to customers. By aggregating the projects, TECO can optimize capital spending, maximize functionally, and achieve efficiency in resource deployment. Witness Lukcic testified that this approach enables a centralized project management, reduces redundancy, and enhances resource efficiency. We find that TECO appropriately evaluated the costs of the GRR Projects in its request by grouping like projects together for efficient spending.

Furthermore, we agree with TECO that customer demand and activities are changing and that the electric grid needs to be updated to meet those demands. TECO's GRR Projects will evolve TECO's electric grid to meet the demands noted above while also providing inherit reliability and safety benefits. Based on the foregoing, we find TECO has met its burden of proof in relation to the GRR Projects and adequately demonstrated these projects are in the customers' interest.

We therefore approve the proposed Grid Reliability and Resilience Projects, with capital costs of $128.9 million, to be included in the 2025 projected test year without any adjustments. The GRR Projects are in the customers' interest, will evolve the electric grid to meet customer demands, and will also provide reliability and safety benefits.

H. Energy Storage Projects (Issue 20)

1. Analysis

TECO requested to add four energy storage projects: Dover Energy Storage Project (Dover), Lake Mabel Energy Storage Project (Lake Mabel), Wimuama Energy Storage Project (Wimuama) and South Tampa Energy Storage Project (South Tampa) in the 2025 projected test year. TECO witness Stryker stated that the energy storage projects had initial projected in-service dates of September 2024, April 2025, February 2025, and April 2025, respectively. The storage capacity of the four energy storage projects is 15 MW, 40 MW, 40 MW and 20 MW, respectively. The projects will utilize lithium-ion battery technology and would represent a total addition of 115 MW of energy storage capacity to TECO's system. TECO witness Stryker asserted that the capital investment for the energy storage capacity projects would total $156.1 million, consisting of $136.8 million in construction costs and $19.3 million in contingency. TECO later indicated that the in-service date for two of the proposed energy storage projects, and location of one of the energy storage projects, would be revised from its initial Petition. Hence Lake Mabel's in-service date was accelerated from April 2025 to January 2025 and South Tampa's in-service date was delayed from April 2025 to December 2025. And the South Tampa Energy Storage Project construction location was relocated to TECO's Bayside Power Station which delayed the in-service date and led to the South Tampa Energy Storage project being renamed the Bayside Energy Storage Project (Bayside).

TECO witness Aponte testified that the four proposed energy storage projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the energy storage facilities and omitting the energy storage facilities. This comparison was used to determine the system CPVRR. The analyses showed that the addition of the four energy storage facilities would result in a CPVRR savings of $151.2 million for customers. The majority of the CPVRR savings associated with the energy storage projects appear to be from fuel and PTC savings that the projects would provide. Witness Aponte asserted that the next-best alternative to the construction of the proposed energy storage projects the Company explored was combustion turbine (CT) technology, which was ultimately rejected. This decision was influenced by the fact that the resource plan that included the four energy storage projects produced a lower CPVRR in comparison to the CT alternative resource plan. Additional non-economic benefits of the energy storage facilities include: smaller operational footprints, a more rapid location siting process, and deployment in smaller capacity increments to better fit TECO's winter capacity needs.

No intervenor provided testimony regarding whether the Energy Storage projects should be included in the 2025 test year. In its brief, OPC provided no comment on the cost-effectiveness of the projects; but recommended the depreciable service lives of the units be increased from 10 to 20 years. Both FIPUG and FRF echoed OPC's position regarding depreciable service lives. However, we have addressed the appropriate depreciation life in Issue 7. Sierra Club, FL Rising/LULAC, FRF, and Walmart agreed with TECO's proposed energy storage projects.

2. Conclusion

We find that the proposed energy storage projects provide cost-effective energy for TECO's system that will provide savings for customers and bolster TECO's renewable energy portfolio. We base this finding and decision on the evidence in the record and uncontroverted testimonies of TECO witnesses Aponte and Stryker as detailed in our analysis. Therefore, the four energy storage projects, with an estimated total capital cost of $156.1 million, shall be included in the 2025 projected test year with no adjustments.

I. Corporate Headquarters (Issue 21)

1. Analysis

TECO witness Aldazabal testified that TECO is relocating its headquarters from TECO Plaza in Downtown Tampa to a new 18-story tower in Midtown Tampa. A portion of the tower will be purchased by TECO, with rights to approximately 740 parking spaces. This new headquarters will house TECO and its affiliate Peoples Gas System, Inc. TECO will occupy six floors and Peoples Gas will occupy three floors. Each company will own its share of the tower. The anticipated in-service date is June 1, 2025, with a cost of $188.7 million.

As explained by witness Aldazabal, TECO has leased TECO Plaza for 40 years and the lease expires in 2025. TECO evaluated multiple options prior to selecting the Midtown Tampa location. As part of the evaluation, TECO developed ten scoring criteria for each option that included resilience, security, connection to community, walkability, parking, nearby amenities, talent recruitment, dedicated elevators, dedicated lobby, building signage, and sustainability. In addition, TECO evaluated three scenarios: (1) leasing TECO Plaza; (2) purchasing TECO Plaza; and (3) purchasing the Midtown location. The 30-year CPVRR for continuing to lease the Plaza is $209.5 million, for purchasing the Plaza is $203.4 million, and for purchasing Midtown is $210.2 million. This analysis showed that there is less than a $1 million net present value differential between continuing to lease the existing corporate headquarters and purchasing the Midtown location.

Witness Aldazabal explained that continuing to lease an aging building designed over 40 years ago, without parking infrastructure, with outdated systems, and susceptible to low levels of flood waters, was not in TECO's best interest. In addition, witness Aldazabal testified that customers will benefit from TECO owning the building from the equity accumulation and from the Midtown location which provides greater resilience in harsh weather conditions because it is inland and built to modern code standards. Furthermore, the Midtown location offers modern facilities, dedicated parking, more efficient floor layouts that will accommodate more team members, reduce space needs in the future, and improve employee satisfaction, which should result in lower employee turnover and costs. The new headquarters will provide TECO with the flexibility of right of first refusal to lease vacant space on other floors in the building and the right to sublease portions of the floors it will own.

FL Rising/LULAC witness Rábago recommends, in general, that the Commission disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommended that the Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction.

TECO witness Aldazabal rebutted FL Rising/LULAC witness Rábago's testimony by pointing to a CPVRR calculation for the new Corporate Headquarters which was then compared to two alternatives. The Company further compared this quantitative assessment against the resilience and qualitative benefits that the new Midtown location provides. In addition, TECO witness Aldazabal testified that TECO created an internal team of 18 director-level employees to evaluate several criteria and also identified several qualitative drawbacks to remaining in TECO Plaza, including flooding and storm surge risk, available capacity limits, and lack of dedicated parking. TECO determined that the Midtown location was the best alternative from a value, resilience, and employee retention and satisfaction perspective. Furthermore, as the analysis proceeded, the need to locate the Company's headquarters away from potential flooding became a more important priority, especially since the economics of the options being considered were about the same. The Company weighed the identified qualitative benefits of the Midtown location against the approximately $1 million difference in CPVRR cost and concluded that the benefits outweighed the $1 million difference in cost.

2. Conclusion

We find TECO's decision to purchase the Midtown headquarters location to be reasonable. TECO has met its burden of proof by providing both a CPVRR analysis and detailed qualitative benefits that the new Midtown location will provide. One such qualitative benefit is that the structure will be more storm resilient and built to standard with current building codes. Another is that relocating TECO employees to the new Corporate Headquarters will provide additional space for expansion. Therefore, the proposed Corporate Headquarters, with a capital cost of $188.7 million, shall be included in the 2025 projected test year without any adjustments.

J. South Tampa Resilience Project (Issue 22)

1. Analysis

The South Tampa Resilience Project (STR Project) is a two-phase project consisting of two pairs of 18.5 MW reciprocating internal combustion engines (RICE) with in-service dates of December 2024 for Phase I and October 2025 for Phase II. The STR Project is located on MacDill Air Force Base (MAFB), which agreed to lease the land at no cost to TECO in exchange for the provision of electrical service in the event of a validated threat against MAFB. Under normal operations, the STR Project will be a system asset that serves all customers. The future installed project cost is approximately $167 million (including AFUDC). The STR project will strengthen the Company's reserve margins and can be dispatched instead of larger combustion turbines, which will result in fuel savings.

The dispute on this issue revolves around whether the STR Project is necessary and/or too costly. TECO witness Aldazabal described the project as needed to provide flexibility to its resources and resilience based on its location. Also, by providing quick-start capability, the units will improve the Company's utilization of its existing fleet of generating assets due to the increased flexibility, reduced maintenance intervals, improved heat rates, faster ramp rates, and lower turndowns of the STR Project. TECO witness Aponte asserted that the STR Project is cost-effective based on a CPVRR analysis that projects net benefit to customers of approximately $10 million, excluding emission reductions. This net benefit includes a projected fuel savings to customers of $137.9 million from the RICE generating units. The remaining savings are primarily associated with the delay or avoidance of other generating assets, and their related transmission components.

OPC has not proposed eliminating the STR project, but it did indicate concerns that an increase in rates will create an affordability challenge for many ratepayers. OPC was also concerned about the lack of sufficient federal government funding that recognizes the benefits being provided to MAFB and questioned whether TECO proved the project was prudent or that resulting customer rates were fair, just, and reasonable. Meanwhile, FL Rising/LULAC witness Rábago recommended the Commission deny any rate recovery for the STR Project due to several concerns, including a lack of support of a benefit-cost analysis, the addition of polluting fossil generation, and a lack of direct financial support from MAFB for the benefits provided.

a. The STR Project is Reasonable

We disagree with OPC's and FL Rising/LULAC's arguments. We find that the record evidence shows the STR Project's costs, funding, and cost-benefit analysis are reasonable. Although the federal government did not provide monetary funding for this project, it did provide in-kind support in the form of a no-cost land lease to TECO, which should not be discounted. TECO also followed prudent procurement practices because all major contracts were competitively bid and thoroughly evaluated prior to contract award. TECO staffed the project with skilled project, engineering, and construction staff to ensure work is completed in an efficient, high-quality manner. Additionally, witness Aponte did conduct a cost-benefit analysis as demonstrated by the CPVRR estimating a $10 million net benefit to ratepayers and establishing an economic need for the project. As mentioned previously, this net benefit includes projected fuel savings to customers of $137.9 million. Witness Aponte also accounted for the operational benefits including strengthening near-term reserve margins, improving reliability, enhancing dispatch flexibility, and further insulating customers from disruptions during extreme weather events. We therefore conclude that the STR Project is cost-effective and find that the cost-benefit analysis has adequately supported the economic need for the project.

b. The STR Project's Operational Benefits Outweigh its Costs

We find the STR Project to be necessary for reliability and resiliency based on the evidence and testimony presented by TECO. TECO demonstrated that the project is needed to provide the Company with operational flexibility of resources and resilience by providing quick-start capability. This quick-start generation will also give the added benefits of resilience in the middle of a dense load center and alleviation of transmission constraints in the area. Witness Aponte attributed the increasing amount of solar generation and its operating characteristics with the need for faster start and ramp times, as rapid changes in solar output can lead to traditional generation being forced offline or operating inefficiently to maintain reliability. The RICE will help mitigate intermittent generation problems from diverse sources of energy, like solar panels' lowered performance during cloudy parts of the day. The RICE will improve the Company's utilization of its existing fleet of generating assets due to the increased flexibility, reduced maintenance intervals, improved heat rates, faster ramp rates, and lower turndowns of the STR Project.

Witness Aponte also demonstrated additional operational benefits from this project including strengthening near-term reserve margins, improving reliability, enhancing dispatch flexibility, and further insulating customers from disruptions during extreme weather events. As to FL Rising/LULAC's concern regarding fossil fuel generation, there is evidence that the operational flexibility this project provides may promote an expansion of solar generating assets.

The RICE also contribute to the reliability of Florida's energy grid and national security because of their location and generating output. These units have a total capacity of approximately 37 MW per pair, but the load requirements for MAFB are 26 MW. Meaning other customers will benefit from additional capacity during normal operations. Only in the extremely rare event of a validated threat to MAFB would the base be electrically islanded and entirely powered by the STR Project. Such a validated threat has not occurred since September 11, 2001.

2. Conclusion

Although we considered OPC and FL Rising/LULAC's arguments, we are persuaded by the evidence in the record demonstrating that the STR Project is cost-effective, reasonable and prudent, and will provide operational and reliability benefits to customers. Moreover, the STR Project's location will provide flexibility in resource dispatch as well as promote substantial fuel savings. For these and the reasons articulated above, we find that the STR Project is reasonable and prudent, contributes to the reliability of the energy grid while strengthening national security, is cost-effective, and provides a host of operational benefits to all customers. We therefore approve the inclusion of the STR Project, with a capital cost of $167.245 million, in the 2025 projected test year without any adjustments.

K. Bearss Operations Center Project (Issue 23)

1. Analysis

TECO requested its Bearss Operations Center (BOC) project be included in the 2025 projected test year. This project consists of replacing TECO's existing Energy Control Center (ECC) and Ybor Data Center with the BOC. This project also includes Energy Management System (EMS) upgrades, which are new map boards and dispatching consoles to match the operating assets within the facility. The anticipated in-service date for the BOC is June 2025 with a total cost of $307.4 million. The EMS upgrades are projected to be completed by October 1, 2025, with a total cost of $27.6 million.

TECO will continue to utilize the two buildings which housed the Ybor Data Center and the ECC. The Ybor Data Center will become the Customer Experience Center for both TECO and Peoples Gas, and the existing ECC will be repurposed into an Engineering Center for Electric Delivery. Several Customer Experience departments and employees will relocate from their current home at TECO Plaza to the Ybor location instead of relocating to the BOC or the Corporate Headquarters. According to TECO, this change will more efficiently and effectively consolidate Customer Experience functions and departments into a single location.

In addition, TECO explained that it has a continuing lease of $181,687.81 per year, with a scheduled CPI adjustment every five years for the Ybor Data Center. As explained above, the Ybor Data Center will continue to be used for employee work offices, so the Ybor Data Center lease costs are included as part of the Company's revenue requirement calculation. TECO witness Aldazabal testified that the Ybor lease is below market value and it is a very economical lease for TECO. He indicated that is one of the reasons TECO wants to maintain the Ybor Data Center. As TECO owns the ECC, there is no lease.

TECO explained that the ECC has been TECO's primary control center since June 1989, serving customers for 35 years. The ECC operates 24/7/365 and was constructed under 1980 building codes and in a Level B evacuation zone. TECO's customer base has doubled since the ECC was first used and there is no room for growth within the ECC; as such, TECO considers the ECC to be at its "End of Life." The Ybor Data Center was also designed using 1980 technology and building codes. In addition, the Ybor Data Center is not hardened to withstand a major hurricane and is located within a storm evacuation zone. As stated above, TECO owns the ECC and the lease for the Ybor Data Center is below market value. While these two buildings are older and in flood prone areas, the buildings will house non-essential employees, like the Customer Experience Center and the Engineering Center for Electric Delivery unlike the BOC which will house all of TECO's cyber assets and operate TECO's command and control capabilities. The BOC will also house all of TECO's mission critical assets and departments.

TECO based its decision to replace the ECC and Ybor Data Center on three factors: (1) storm resilience; (2) space needs; and (3) strategic objectives. Both existing facilities are subject to high winds and storm surge in the event of a major hurricane tracking into Tampa Bay. The BOC will be located in a safer, higher, and more inland location, and will be designed to withstand winds up to 171 mph. TECO argued the importance of security and storm resilience for BOC, as it will house imperative functions.

TECO witness Aldazabal explained that TECO evaluated its existing facilities and future space plans, potential new site locations, and conceptual site layouts to replace the ECC and Ybor Data Center. The site location criteria included size, security risk, flood zone, topography, environmental conditions, employee commute, and relay service capability. TECO determined that the Bearss location was the best option because a modern, storm hardened facility will allow TECO to respond faster to customer outages without having to recover its own control of the grid first. The new facility is also better suited to withstand other potential threats such as physical, biological, and chemical.

TECO's current EMS went in-service in 2017. TECO upgrades its EMS every seven years to stay current; however, the current EMS software does not have the capabilities to support the grid's overall performance and will no longer be supported. The new BOC facility will have new situational awareness features such as visual displays, alarming features, operator consoles, and training simulators. In addition, the latest release of the EMS platform offers new functionalities that will be able to support the grid and growth.

No intervenor specifically testified the BOC project. However, FL Rising/LULAC witness Rábago recommended that the Commission should, in general, disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommended that the Commission should disapprove any rate recovery for new building construction until TECO produces a comprehensive BCA that fully considers alternatives to new building construction. Witness Rábago did not identify issues with this project aside from its generic position regarding a BCA.

2. Conclusion

We find that TECO adequately evaluated and supported its decision to replace the ECC and Ybor Data Center. TECO's decision was based on storm resilience, space needs, and strategic objectives. The BOC will be located inland and will be designed to withstand 171 mph sustained hurricane winds. The BOC will provide more space for employees and equipment and will have room to grow. TECO's customer base has doubled since the ECC first started being used 35 years ago and there is no longer enough space to efficiently handle matters related to this increased demand. In addition, the BOC will be designed to accommodate the newer strategic EMS upgrades that will better support the electric grid's overall performance. TECO has met its burden to include the BOC project in the test year given the factual circumstances and the objective, clear reasons supplied. Therefore, the proposed BOC project, with a total cost of $335.0 million, shall be included in the test year without any adjustments.

L. Polk 1 Flexibility Project (Issue 24)

1. Analysis

Polk Unit 1 is a 220 MW Integrated Gasification Combined Cycle (IGCC) plant that entered commercial service in 1996 with a 1x1 configuration consisting of a single CT with an attached HRSG, connected to a single ST. Polk Unit 1 is a one-of-a-kind installation because it is supplied fuel via an integrated gasification facility that converted its coal or petcoke feedstock into syngas which was then fired in the combustion turbine. The unit can also operate on natural gas as needed, and has been fueled by natural gas and not the syngas from the gasifier since 2018. TECO witness Aldazabal stated that due to its age and operating history, it is in need of a major maintenance overhaul, and the existing combustion turbine system is no longer supported by its original equipment manufacturer, General Electric Company.

In lieu of maintaining the current configuration, TECO proposes the Polk 1 Flexibility Project (Flexibility Project), which consists of the conversion of Polk Unit 1 to a simple cycle configuration using natural gas as its primary fuel while keeping the gasification, HRSG, and ST in reserve for a possible future conversion back to an IGCC. Witness Aldazabal asserted that by designing and operating the unit as a CT that TECO would avoid significant capital expenses associated with upgrades to the existing combined cycle system, and that operations would benefit from the unit's flexibility, including faster start times, higher ramp rates, and lower turndowns. In cross-examination, TECO witness Aponte agreed that the Flexibility Project does not add capacity to the system. In fact, the converted output of the unit is about 20 MW less than the current combined-cycle unit with 220 MW.

a. Cost-Effectiveness

The Flexibility Project is projected to have an overnight construction cost of $90.1 million. TECO witness Aponte asserted that TECO’s economic analysis shows the proposed project is cost-effective and estimates a CPVRR benefit of $166.9 million excluding emissions. The witness’ net-benefit evaluation is based on the comparison of retaining the unit in its current IGCC configuration versus the simple cycle CT conversion proposal.

In their briefs, FL Rising/LULAC states that the Flexibility Project does not add capacity to TECO's service territory, and should be rejected. Witness Aldazabal admits that TECO is planning to use Polk Unit 1 at less than 5 percent of its capacity factor. Sierra Club witness Glick argued that even with the CT conversion, Polk Unit 1 is non-economical. The witness further asserted that the Company failed to consider retirement as an option, excluding a study conducted in 2022 that assumed a 2028 retirement date.

However, according to TECO witness Aldazabal, TECO evaluated three alternatives: (1) the retirement of Polk Unit 1, (2) an “in-kind” upgrade that would maintain the unit as-is, and (3) the Flexibility Project. Witness Aldazabal testified that TECO selected the most beneficial scenario for customers by opting to convert the unit to simple cycle mode, and that even when compared to the 2028 retirement scenario produces an additional $24.6 million in savings. TECO witness Aponte testified that the Polk Unit 1 retirement analysis revealed that no change to the unit is the most expensive option, followed by the retirement option, and the conversion to simple cycle being the most cost-effective option.

b. Remaining Non-Simple Cycle Assets

TECO witness Aldazabal stated the Company plans to retain the Polk Unit 1 gasifier, HRSG, and ST in the event petcoke became economically viable in the future and provide a fuel diversity option. These components can be returned to service within a year. During cross-examination, witness Aldazabal admitted that TECO has not estimated the cost of returning Polk Unit 1 to service as an IGCC. He further stated that for the return to service of those components to be feasible, the reduction in price from natural gas to coal or petcoke would need to occur for an extended period of time greater than a year and the price differential would need to cover the cost of conversion.

Sierra Club witness Glick argued TECO is not likely to return these components to service and they should be retired. Witness Glick asserted that the amount of time required for conversion back to operating on alternate fuels such as petcoke makes it unlikely that the unit would ever return to combined cycle service, and certainly could not do so during a short-term fuel disruption or price spike. TECO witness Aldazabal confirmed that TECO has operated the unit on natural gas alone since 2018, even in the face of gas supply and price concerns due to the short-term duration of the price or supply shocks.

A 2025 retirement of the gasifier, CT, and ST at Polk Unit 1 would result in an unrecovered capital investment in the amount of $142,251,955. A 2025 retirement would also result in an un-accrued dismantlement cost of $1,692,786. In the event of a retirement, we hereby establish a capital recovery schedule with an 11-year amortization period to address recovery of the remaining balance in rate base.

2. Conclusion

We find TECO's past behavior since 2018, the amount of time needed to complete a physical conversion back to syngas fuel sources, and the sustained period of time where fuel price differentials would need to be sufficient to cover the cost of conversion, all make any future conversion unlikely. It is unlikely that these components will be able to provide fuel diversity benefits in the event of fuel supply shocks in a reasonable timeframe. We therefore agree with Sierra Club's recommendation that the gasifier, HRSG, and ST units be retired.

The proposed Polk 1 Flexibility project, with a total cost of $90.1 million, will be included in the 2025 projected test year. The conversion of Polk Unit 1 to a natural gas-fired simple cycle unit is projected to be more cost-effective for ratepayers than continuing as a combined cycle unit and incurring major capital expenses. However, TECO will retire the remaining portions of Polk Unit 1 IGCC system, including the gasification equipment, HRSG, and ST because they are not likely to return to service. Due to this early retirement, an adjustment shall be made to remove $142,251,955 and a capital recovery schedule with an 11-

year amortization period shall be implemented to address recovery of the remaining balance in rate base.

M. Plant in Service (Issue 25)

1. Analysis and Conclusion

OPC argued in its brief that the Distribution Feeder Hardening costs should be disallowed from Plant in Service and considered in the Storm Protection Plan and Storm Protection Plan Cost Recovery Clause (SPPCRC). TECO responds that the Distribution Feeder Hardening costs have been recovered this way in prior years and this approach recognizes that the depreciation expense for the removed assets incorporated the recovery of the cost of removal in rate base. We will allow the Distribution Feeder Hardening costs to be included in Plant in Service, as it has been in prior years.

Our other decisions elsewhere in this Order have also impacted Plant in Service. Based on our rulings on Issues 14, 15, 16, and 24, Plant in Service will be reduced by $473,023,447. Plant in Service for the 2025 projected test year shall therefore be $12,945,054,553.

N. Accumulated Depreciation (Issue 26)

1. Analysis and Conclusion

In its original filing, TECO stated the amount of Accumulated Depreciation that should be approved for the 2025 test year is $4,004,807,000. Based on our rulings and adjustments made on in Issues 7, 11, 15, 16, 20, 22, and 24, Accumulated Depreciation should be decreased by $325,142,466. We therefore find that the correct Accumulated Depreciation value for the test year is $3,679,664,534.

O. Construction Work in Progress (Issue 27)

1. Analysis and Conclusion

In its original filing, TECO reflected $230,175,000 of Construction Work in Progress (CWIP) in the 2025 projected test year. No parties introduced any testimony disputing this amount. In its brief, FL Rising/LULAC argue that no CWIP should be included in the projected 2025 test year. Additionally, OPC argued for the removal of CWIP associated with the GRR Projects, but did not cite any specific amount.

Although we do not permit recovery at this time of the 2026 GRR Projects, as addressed with Issue 96, we do find that an adjustment to 2025 CWIP is needed because our other decisions have impacted CWIP. Based on our decision on Issue 14, CWIP shall be reduced by $12,190,000, which is the 13-month average of the $18.2 million associated with the Future Environmental Compliance project. Therefore, we find, and approve, that $230,175,000 in CWIP for the 2025 projected test year is appropriate and supported by the evidence presented by TECO.

P. Property Held for Future Use (Issue 28)

1. Analysis and Conclusion

TECO states that the amount of Property Held for Future Use that should be approved for the 2025 projected test year is $68 million. FL Rising/LULAC argued that no Property Held for Future Use should be included in the projected 2025 test year. No other parties have given arguments against the inclusion of Property Held for Future Use.

We find TECO has provided sufficient support to justify an amount of Property Held for Future Use in the 2025 projected test year of $68,034,000.

Q. Other Post-Retirement Employee Benefits Liability (Issue 29)

1. Analysis and Conclusion

TECO stated that the amount of unfunded Other Post-Retirement Employee Benefits (OPEB) liability that should be included in rate base is $70,740,641. TECO argued that it did not undercapitalize OPEB expense and the appropriate amount is reflected in Issue 54. OPC argued that an adjustment to unfunded OPEB liability should be made in correlation to adjustments it recommended in Issue 54. FL Rising/LULAC stated that no OPEB should be included in the projected 2025 test year where a return on equity is earned. No other parties have given arguments against the inclusion of OPEB.

We find TECO has provided sufficient support and justification to include unfunded OPEB liability. Consistent with our resolution of Issue 54, no adjustment to unfunded OPEB liability is warranted. Therefore, the amount of OPEB that shall be included in rate base is $70,740,641.

R. Fuel Inventories (Issue 30)

1. Analysis and Conclusion

Fuel inventories are included in working capital, which is a component of rate base. The maximum value for fuel inventory to be included in working capital is defined as the 60-day burn rate for each type of fuel (i.e., coal and fuel oil).

The 13-month average fuel inventory value for TECO’s system was $36,824,000. TECO witness Chronister testified during direct examination that the Company subsequently made a downward adjustment of approximately $189,000 to reflect the 60-day burn level for its fuel oil inventory. Additionally, according to witness Chronister, the projected 2025 coal inventory was already below the 60-day burn rate level and warranted no adjustment. The fuel oil adjustment resulted in TECO's requested average fuel inventory value decreasing to $36,635,000. The jurisdictional amount, calculated using a separation factor of 0.996559, is approximately $36,509,000. We note that FL Rising/LULAC and Sierra Club suggested a fuel inventory fuel value of $0 but neither put forward specific testimony to support that value. Accordingly, based on the record evidence before us, we find that TECO's proposed 2025 jurisdictional fuel inventory amount of $36,509,000 is reasonable.

S. Working Capital (Issue 31)

1. Analysis

OPC witness Mara testified that TECO has historically maintained and budgeted for an excessive number of spare transformers, which have a capital cost of approximately $1 million each. Witness Mara argued that four 37 megavolt-ampere (MVA) transformers should be removed from rate base, which would still allow the Company four remaining spares in the 2024–2025 time period. TECO witnesses Whitworth and Chronister both recommended the Commission reject witness Mara's arguments because the equipment is needed for system reliability and the lead-time to obtain this class of transformers is approximately 2 or 3 years. Witness Whitworth argued that the Company has experienced approximately 4.2 transformer failures annually for the period 2012 through 2023, whereas the Company projects purchasing transformer replacements of 4.8 annually for the period 2021 through 2027 to adjust for customer growth and allow for proactive replacements before failure. Witness Whitworth also argued that maintaining its proposed inventory avoids the need for emergency replacements, which would result in higher costs.

We find that TECO has established a reliability need by preponderance of the evidence. We are particularly persuaded by its demonstrated history of over four transformer failures each year from 2012–2023, an estimated increase in failure occurrence in the future, and the amount of time needed to obtain replacements (if not already on hand). Given these circumstances, the amount of spare transformers TECO proposes to have ready is reasonable.

2. Conclusion

We approve that TECO's proposed transformer acquisitions be included in the test year. As mentioned previously, they will allow the Company to maintain system reliability and avoid expensive emergency replacements. Based on our rulings on Issues 24, 31, 45, and 64, and our decision here to approve the transformer acquisitions, Working Capital will be increased by $137,300,393. Therefore, the total Working Capital allowance for the 2025 projected test year shall be $223,971,393.

T. Rate Base (Issue 32)

1. Analysis and Conclusion

This is a fall-out matter based on our decisions on Issues 7, 11, 14, 15, 16, 24, 31, and 64. Consistent with those rulings, rate base for the 2025 projected test year shall be decreased by $22,771,588 when compared to what TECO petitioned for. Therefore, we approve a test year rate base of $9,775,379,412.

VI. Cost of Capital

This section discusses the determination of the appropriate Cost of Capital to be used by TECO in establishing its revenue requirement. These issues were numbered in the Prehearing Order as numbers 33 through 40. These items include, among others, the appropriate level of Accumulated Deferred Taxes (Issue 33), Short and Long-Term Debt (Issues 36 and 37, respectively), the appropriate Equity Ratio (Issue 38) and the Return on Equity that the company should realize (Issue 39). The determination of the appropriate Return on Equity was the subject of voluminous testimony submitted by several witnesses.

A. Accumulated Deferred Taxes (Issue 33)

1. Analysis

TECO requested a total accumulated deferred income tax (ADIT) balance of $980,855,000, to be included in the 2025 projected test year capital structure, which is presented on MFR Schedule D-1a. TECO later revised its amount after filing its letter of August 22, 2024, to $980.2 million to reflect adjustments to rate base during the proceeding. None of the parties made a specific objection to TECO's adjusted amount of ADITs.

TECO witness Strickland explained that the ADITs for the 2025 forecasted period have been computed based on the projected book/tax temporary differences and in accordance with Generally Accepted Accounting Principles (GAAP), the requirements of the Commission, and IRS rules, including special provisions applicable to utilities. TECO calculates the deferred taxes and the related accumulated deferred income tax based on the projected book/tax temporary differences for the 2025 forecasted period. Under U.S. Treasury Regulation § 1.167(1)-1, when a projected test period is used to set rates and the newly determined rates are expected to be in effect for all or a portion of that test period, the utility plant ADIT additions in the portion of the test period in which the new rates are expected to be in effect must be pro-rated over the period for which the new rates are expected to be in effect. None of the parties objected to TECO's proration adjustment.

2. Conclusion

We previously approved a total rate base amount of $9,775,379,412. When this amount is reconciled pro rata over all capital sources, the corresponding amount of ADITs is $978,507,000. We therefore approve $978,507,000 of ADITs for inclusion in the 2025 projected test year capital structure.

B. Unamortized Investment Tax Credits (Issue 34)

1. Analysis

TECO originally presented its 2025 projected test year capital structure based on a 13-month average consisting of unamortized ITCs in the jurisdictional adjusted amount of $211.7 million at a cost rate of 8.26 percent as shown on MFR Schedule D-1a. TECO later revised this amount in its August 22, 2024 letter to $211.5 million in order to reflect adjustments to rate base during the proceeding. TECO maintains that the change would not materially impact the overall weighted average cost of capital, and thus, its requested investment tax credit cost rate. OPC argued that the cost rate for ITCs, in the projected capital structure, should be 7.18 percent with an amount of $178,098,000. FL Rising/LULAC argued the ITCs should be flowed back to customers over a 10-year period with a zero-cost rate because TECO already receives a return on investment for the capital expenditures associated with battery assets. FIPUG, FRF, Sierra Club, and Walmart adopted the position of OPC, while Fuel Retailers took no position on this Issue. FEA's position on this Issue cites deferred income taxes, not ITCs.

TECO witness Strickland explained the ITC balance for the 2025 forecasted period was calculated in accordance with GAAP, the requirements of the Commission, and the IRS rules, including special provisions applicable to utilities. Witness Strickland's forecasted amount of ITCs reflect an amortization over 30 years for the Solar ITCs as proposed in the Company's recently filed depreciation study. While the majority of the ITC balance was generated during the 2017–2021 period as a result of the Company's investment in solar facilities, the ITC balance in 2024 and 2025 is also projected to increase due to new ITCs generated by TECO's investment in energy storage facilities. TECO initially established the energy storage facilities in this rate case at a 10-year service life. However, the Company later amended the service life to reflect a 20-year service life in an updated revenue requirement document submitted on August 22, 2024.

The unamortized ITC balance is a regulatory tax liability component of the capital structure which earns the weighted average cost rate of investor sources of capital, and is consistent with the methodology used in prior rate case proceedings. TECO witness Chronister asserted the cost rate of 8.26 percent is reasonable because it reflects the weighted cost of investor sources of capital, which is the Commission-approved method for calculating the cost rate for ITCs. TECO's calculation for the ITC cost rate is summarized in Table 7.

Table 7
TECO ITC Cost Rate Calculation (Dollars in 000's)

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	$3,505,671	41.57%	4.53%	1.88%
Short Term Debt	$376,625	4.43%	3.90%	0.17%
Common Equity	$4,593,473	54.00%	11.50%	6.21%
	$8,059,316			8.26%

OPC witness Kollen applied OPC witness Woolridge's recommended ROE of 9.50 percent to his proposed capital structure and obtained an ITC cost rate of 7.18 percent. OPC's recommended ITC cost rate is summarized in Table 8.

Table 8
OPC ITC Cost Rate Calculation (Dollars in 000's)

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	$3,536,333	41.57%	4.53%	1.88%
Short Term Debt	$376,625	4.43%	3.90%	0.17%
Common Equity	$4,593,473	54.00%	9.50%	5.13%
	$8,506,431			7.18%

The IRC regarding the flow back of ITCs per the normalization rules require that the ITC cost rate should not have an impact on the overall investor sourced cost of capital. Pursuant to 26 C.F.R. § 1.46-6, the unamortized (deferred) investment tax credits are assigned a cost of capital rate equal to the composite cost of capital for all other capital investments based on common equity, preferred stock, and long-term debt.[38] The appropriate investor sources to use in the calculation of the ITC cost rate include long-term debt and common equity, excluding short-term debt, as required by the IRC regulations. We ultimately approve an ROE of 10.50 percent herein. The lower ROE reduces the Company's requested ITC cost rate from 8.26 percent to 7.90 percent as shown in Table 9.

[38] 26 C.F.R. § 1.46-6(b)(3)(ii)(B) requires that, for purposes of determining the cost of capital rate assigned to the tax credit and the amount of additional interest that the taxpayer would pay or accrue, the composition of the capital that would have been provided if the credit were unavailable may be determined: (1) on the basis of all the relevant facts and circumstances; or (2) by assuming for both such purposes that such capital would be provided solely by common shareholders, preferred shareholders, and long-term creditors in the same proportions and at the same rates of return as the capital actually provided to the taxpayer by such shareholders and creditors.

Table 9
ITC Cost Rate Calculation (Dollars in 000's)

	Jurisdictional adjusted capital	Capital Ratio	Cost Rate	Weighted Avg. Cost
Long Term Debt	$3,528,800	43.498%	4.53%	1.97%
Common Equity	$4,583,688	56.502%	10.50%	5.93%
	$8,112,488			7.90%

In resolving Issue 7, we ruled that the pre-2022 solar service lives be adjusted from 30 to 35 years. In OPC witness Kollen's work papers, he calculated an ITC balance difference of $1,240,667 between establishing a 35-year versus a 30-year service life. The corresponding adjustment is an increase to the ITC balance of $1,240,667. Based on the increase in service life, the ITC balance would be reduced at a slower rate due to the additional 5 years of amortization.

Later in this Order, when addressing Issue 65, we order that the ITCs related to the battery storage projects be amortized over 5 years as opposed to TECO's proposed 10 years. As a result, the annual ITC amortization amount should be increased by $2,883,352 from the Company's amount in its filing of $3,743,460. This adjustment results in a decrease to the unamortized balance of $2,883,352 since the balance is being reduced at a faster annual rate.

The net effect of our adjustments on the ITC unamortized balance is a decrease of $1,340,644. The 13-month ITC balance in MFR Schedule D-1a is $259,351,150 (per Company books). The new per books balance would be $259,351,150 + $1,240,667 - $2,883,352 = $257,708,465, for a decrease of $1,642,685. The jurisdictional amount is lower due to TECO's pro rata and jurisdictional adjustments: $1,642,685 x 0.821 x .994068 = $1,340,644. We previously ordered a total 2025 rate base amount of $9,775,379,412. After pro rata adjustments to reconcile the capital structure to rate base, the ITC balance is $209,579,000.

2. Conclusion

Therefore, we approve an ITC amount of $209,579,000 at a cost rate of 7.90 percent for inclusion in the capital structure of the 2025 projected test year.

C. Customer Deposits (Issue 35)

1. Analysis

In its initial filing, TECO presented its 2025 projected test year capital structure based on a 13-month average reflecting a customer deposit balance in the jurisdictional adjusted amount of $99.195 million at a cost rate of 2.41 percent as shown on MFR Schedule D-1a. TECO later revised this amount in testimony to $99.1 million after filing its letter in August 2024, to reflect adjustments to rate base during the proceeding. None of the intervenors made a specific objection to TECO's adjusted amount of customer deposits.

TECO witness Chronister testified how the forecasted amount and cost rate for customer deposits are calculated as well as the reasonableness for inclusion in the projected 2025 test year capital structure. Witness Chronister explained 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. Witness Chronister indicated that this practice is reasonable because it reflects a consistent application of long-standing budget process steps and asserted that the cost rate for customer deposits reflects rates approved by the Commission. He further added that it is reasonable to forecast based on the infrequent number of changes made to these rates by the Commission over time.

We find that the calculation of interest on customer deposits complies with the requirements set forth in Rule 25-6.097(5)(a), F.A.C. No party disputes that customer deposits are a component of the capital structure. No argument was made contesting the amount or cost rate that should be included in the 2025 projected test year capital structure. In fact, OPC, FIPUG, FRF, and Walmart all agreed with TECO's as-filed position concerning both amount and cost rate. FL Rising/LULAC also agreed with the amount but did not specify a cost rate. We previously ordered a total 2025 rate base amount of $9,775,379,412. After pro rata adjustments to reconcile all capital sources the corresponding amount of customer deposits is $98,984,000.

2. Conclusion

Therefore, the amount and cost rate for customer deposits that are approved for inclusion in the capital structure for the 2025 projected test year is $98,984,000 at a cost rate of 2.41 percent.

D. Short-Term Debt (Issue 36)

1. Analysis

TECO included the amount of $376.625 million for short-term debt at a cost rate of 3.90 percent in its projected test year capital structure on MFR Schedule D-1a. TECO later revised its amount after filing its August 22, 2024 letter to $376.6 million in order to reflect adjustments to rate base during proceeding. None of the parties raised a specific objection to TECO's adjusted amount of short-term debt or cost rate.

TECO witness Chronister explained how the Company forecasts for short-term debt. The Company's forecasted borrowing needs are based on the combination of budgeted capital expenditures net of forecasted cash from operations and the Company's adherence to the capital structure (46 percent debt, 54 percent equity) which is needed to maintain financial integrity. Witness Chronister asserted the amounts are determined using prudent forecasting of capital expenditures and cash from operations, and the application of TECO's commitment to capital structure ratios that are needed to keep the overall cost of capital low. According to witness Chronister, 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 borrowing at the interest rates estimated for each month in the budget period. We find the method of calculating cost rates here to result in reasonable estimates based on TECO's financial integrity, credit ratings, and forecasts for future market rates.

Witness Chronister explained why the forecasted market rates are higher than market rates at the time of the last rate proceeding. 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 and the forecasted short-term cost rate for 2025 is 3.90 percent. TECO's actual long-term cost rate in 2022 was 4.36 percent and the 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.

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 TECO predicts that short-term rates will be lower in 2025. OPC and other intervening parties did not provide any specific arguments opposing the reasonableness of TECO's forecasted short-term debt amount and cost rate. Based on the current market rates for short-term debt, we find that the forecasted rate of 3.90 percent is reasonable. We previously ordered a total 2025 rate base amount of $9,775,379,412. When this amount is reconciled pro rata over all capital sources to our approved capital structure, the corresponding amount of short-term debt is $375,823,000.

2. Conclusion

Therefore, based on the testimony and evidence referenced in our analysis, we approve for inclusion in the capital structure of the 2025 projected test year a short-term debt amount of $375,823,000 with a cost rate of 3.90 percent.

E. Long-Term Debt (Issue 37)

1. Analysis

In its initial filing, TECO based its 2025 projected test year capital structure on a 13-month average consisting of long-term debt in the jurisdictional adjusted amount of $3.536 billion at a cost rate of 4.53 percent as shown on MFR Schedule D-1a and D-4a. TECO later revised the amount to $3.534 billion in its August 2024 letter to reflect adjustments to rate base during the proceeding. Only FL Rising/LULAC and FEA took an opposing position on the amount of long-term debt to reflect their respective positions elsewhere regarding equity ratio.

TECO witness Chronister testified 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. Witness Chronister affirmed the cost rates are reasonable estimates based on TECO's financial integrity, credit ratings and forecasts for future market rates.

Witness Chronister explained the Company's actual long-term cost rate in 2022 was 4.36 percent and the forecasted long-term cost rate for the 2025 projected test year is 4.53 percent. Witness Chronister detailed how 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. Witness Chronister emphasized and we agree the forecasted 2025 long-term debt cost rate is reasonable because it reflects: (a) embedded existing cost rates; (b) cost rates for the long-term debt assumed by TECO 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.

We note the cost rate of 4.53 percent was not disputed throughout the proceeding. None of the intervenors filed testimony contesting the long-term debt cost rate of 4.53 percent and no argument was offered by the parties pertaining to the cost rate of long-term debt for the 2025 projected test year capital structure. OPC witness Woolridge testified that he is not contesting the Company's short-term and long-term debt cost rates. Likewise, FEA did not contest the long-term debt cost rate of 4.53 percent throughout the proceeding; however, FEA witness Walters recommended a 52.00 percent equity ratio and suggested that the Company has not reasonably demonstrated the need to be awarded a common equity ratio in excess of 52.00 percent.

Furthermore, we note the primary driver for any adjustment in regards to the amount of long-term debt to include in the 2025 projected test year capital structure is due to a lower equity ratio recommended by FEA and FL Rising/LULAC witnesses as discussed further herein. In addition, we acknowledge the fact FL Rising/LULAC did not contest the cost rate of 4.53 percent; however, FL Rising/LULAC argued the long-term debt amount should be adjusted downwards to account for a reduction to rate base and adjusted upwards to account for a 50-50 equity-to-debt ratio. We address the lower equity ratios recommended by the parties below in the next Issue. Additionally, we have authorized a total rate base amount of $9,775,379,412. When this amount is reconciled pro rata over all capital sources to our approved capital structure, the corresponding amount of long-term debt is $3,528,800,000.

2. Conclusion

The approved amount of long-term debt for inclusion in the capital structure for the 2025 projected test year is $3,528,800,000 at a cost rate of 4.53 percent.

F. Equity Ratio (Issue 38)

1. Analysis

In its filing, TECO requested a projected test year capital structure consisting of an equity ratio of 54.00 percent based on investor-supplied capital for rate setting purposes. TECO's current equity ratio of 54.00 percent was approved by the Commission as part of the 2021

Settlement Agreement in TECO's last rate case by Order No. PSC PSC-2021-0423-S-EI.[39] TECO argued that its equity ratio of 54.00 percent is reasonable and prudent, and needed to support the Company's financial integrity as measured by cash flows and financial leverage. TECO witness Chronister testified that continuing to maintain a strong financial position will allow the Company to attract capital on reasonable terms and continue to provide a safe and reliable electric system for its customers. Witness Chronister explained that financial integrity helps ensure uninterrupted access to capital markets to finance required infrastructure investments as well as to manage unforeseen events. TECO argued that its requested rate increase which includes an ROE of 11.50 percent, and a common equity ratio of 54.00 percent, will maintain the Company's financial integrity and place TECO in the appropriate financial position to fund capital costs for assets and continue providing the high level of reliable service to its customers.

TECO witness D'Ascendis testified that TECO's requested equity ratio of 54.00 percent is reasonable and consistent with the range of common equity ratios maintained by the electric utilities in his proxy group. For 2022, the range of the equity ratios of the 14 electric utilities in the proxy group was 28.90 percent to 56.13 percent with an average equity ratio of 41.49 percent. Witness D'Ascendis also compared the equity ratios of the subsidiary operating electric utility companies included in the proxy group companies of which he determined the range of equity ratios was 38.14 percent to 55.90 percent with an average of 49.05 percent. Witness D'Ascendis reasoned, and we agree, that TECO's equity ratio of 54.00 percent is appropriate for ratemaking purposes because it is within the range of the common equity ratios of the companies in his electric utility proxy group.

OPC witness Woolridge testified that he is not contesting TECO's equity ratio of 54 percent, but also recognized that the Company's proposed capital structure has more equity and less financial risk than the average current capitalizations of the electric companies in TECO witness D'Ascendis' proxy group. OPC explained that witness Woolridge did not offer testimony contesting TECO's proposed capital structure because the 54.00 percent equity ratio was adopted in the 2021 Settlement Agreement and is consistent with how the Company financed its capital needs. Consequently, witness Woolridge recommended an ROE of 9.50 percent that recognizes and accounts for TECO's relatively high equity ratio and lower financial risk.

Witness Woolridge stated that when a regulated utility's actual capital structure contains a high equity ratio, there are two options. The first option is to impute a more reasonable capital structure that is comparable to the average of the proxy group used to determine the cost of equity and to reflect the imputed capital structure in revenue requirements. The second option is to recognize the downward impact that an unusually high equity ratio will have on the financial risk of a utility and authorize a common equity cost rate lower than that of the proxy group. In its brief, OPC contended that witness Woolridge opted to account for TECO's high common

[39] Order No. PSC-2021-0423-S-EI, Issued November 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

equity ratio and lower financial risk in his ROE recommendation as discussed in our discussion of Return on Equity (Issue 39), instead of recommending a lower equity ratio for TECO.

FEA recommended the Commission approve a capital structure with a common equity ratio no higher than 52.00 percent. FEA argued that TECO has not reasonably demonstrated a need for an equity ratio greater than 52.00 percent and that an equity ratio of 52.00 percent strikes a balance between financial stability and the cost of equity that provides a buffer against financial risks without excessively increasing the cost of capital. FEA witness Walters testified that TECO witness D'Ascendis' proxy group of electric companies has an average common equity ratio of 40.50 percent (including short-term debt) and 43.80 percent (excluding short-term debt) as calculated by S&P Global Market Intelligence and Value Line, respectively. TECO's proposed equity ratio of 54.00 percent (including short-term debt) exceeds that of the proxy group's comparable equity ratio of 40.50 percent by almost 14 percentage points. Witness Walters testified that the average authorized equity ratio for electric utilities from 2016 through 2024 was 50.84 percent.

Furthermore, witness Walters testified that TECO has a slightly higher credit rating than that of the proxy group of companies, and although the companies in the proxy group have lower equity ratios, they still are attracting both debt and equity capital investment to fund their elevated capital investments. FEA argued that TECO's credit rating is being hindered two notches as a result of its affiliation with Emera, Inc. Witness Walters explained that TECO's "negative" outlook for its credit rating is driven by the "negative" credit rating outlook for Emera, Inc., and not the cash flow or credit metrics of TECO. FEA argued the utility industries' capital investments are enhancing shareholder value and are attracting both equity and debt capital to the utility industry in a manner that increases the value of utility stocks. FEA therefore concluded the increase in stock value is evidence that utilities have access to equity capital under reasonable terms at lower cost.

In rebuttal, TECO witness Chronister testified that 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. TECO'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. In addition, witness Chronister contended that 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 Commission for utilities in the state of Florida; and (b) would be a downward movement from the equity ratio approved by the Commission for TECO for the last 11 years. FEA's recommendation to reduce the equity ratio to 52.00 percent and the ROE to 9.60 percent at the same time would result in a reduction to TECO's requested revenue requirement of approximately $134.7 million.

2. Conclusion

We recognize that it has been our practice to allow electric utilities to maintain an equity ratio that approximates the Company's actual sources of capital so long as the equity ratio is within the range of 40 percent to 60 percent. TECO has maintained an equity ratio consistent with 54.00 percent for the past 11 years which reflects how the Company is actually financed. The record evidence demonstrates that an investor-source based equity ratio of 54.00 percent will provide TECO with a strong balance sheet that will allow the Company an opportunity to maintain access to capital under reasonable terms in times of financial crisis and weather-related events. TECO's equity ratio of 54.00 percent is also reasonable and prudent because it offsets the Company's higher business risks as compared to the proxy group. They are: (1) a smaller geographic location that gives rise to greater risk from weather events; and (2) high customer growth that gives rise to increased capital expenditures to grow and maintain the Company's infrastructure in order to adhere to its obligation to serve its customers. These business risks are discussed in more detail in the following discussion of ROE as the risks also relate to that determination as well.

We agree with TECO witness Chronister that reducing the Company's equity ratio would potentially have a negative effect on its credit metrics, and that TECO's obligation to serve its customers by modernizing and growing its system is better served by stronger financial integrity. Therefore, we do not make any specific adjustments to the amount of common equity in the capital structure. After reconciliation to the Commission approved rate base amount of $9,775,379,412, the amount of common equity in the capital structure is $4,583,688,000.

We hereby approve an equity ratio of 54.00 percent based on investor-supplied capital for ratemaking purposes for the 2025 projected test year. The amount of common equity in the capital structure is $4,583,688,000.

G. Return on Equity (Issue 39)

1. Summary of the Issue

The ROE is the cost of common equity included in a company's calculation of its weighted average overall cost of capital used to establish a revenue requirement. TECO's current authorized ROE was initially established at 9.95 percent by the 2021 Settlement Agreement which resolved its most recent rate hearing. Due to an increase in interest rates, an ROE trigger provision of the 2021 Settlement Agreement reset TECO's ROE to the current level of 10.2 percent. In its Petition in the present case, TECO requested an ROE of 11.5.

Under the applicable legal standards, the ROE for TECO must be comparable to returns on common equity for other companies having similar risks and it must be sufficient to assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow TECO to raise capital at reasonable costs and terms.[40] OPC witness Woolridge explained that the appropriate ROE for a regulated company requires determining the market-based cost of capital, defined as the return investors could expect from other investments while assuming no more and no less risk. TECO's common equity is not publicly traded therefore a market-based cost rate for the Company cannot be directly observed. To support their respective positions, TECO witness D'Ascendis, OPC witness Woolridge, and FEA witness Walters each filed

[40] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692 (1923) (*Bluefield)* and *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) (*Hope)*.

testimony that included cost of equity financial models applied to a proxy group of publicly-traded electric companies with risk similar to TECO's to derive estimates of the required ROE.

TECO witness D'Ascendis selected 14 companies from the Value Line Investment Electric Utility Group.[41] Both OPC witness Woolridge[42] and FEA witness Walters used the same electric proxy group developed by witness D'Ascendis. An examination of the risk characteristics of the companies in these groups suggests that the two proxy groups are very low risk relative to the overall stock market and are similar in risk to each other.

Interest rates have increased since TECO's last rate case in 2021. Witness Woolridge testified that the 30-year U.S. Treasury Bond yields have increased from approximately 2.50 percent in 2021 to about 4.50 to 4.75 percent in early 2024, with the 30-year U.S. Treasury Bond yield around 4.20 percent at the time of the hearing. While regulated electric company authorized ROEs do not directly track the 30-year U.S. Treasury Bond yields, the bonds can serve as an indicator of capital costs over time. In his rebuttal testimony, TECO witness D'Ascendis updated the results of the cost of equity models and we find it is appropriate to evaluate witness D'Ascendis ROE model results used in his rebuttal testimony rather than his direct testimony because the market-based data is more recent and reflects more recent interest rates.

To estimate the cost of equity, TECO, OPC, and FEA witnesses used the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM). FEA witnesses Walters and TECO witness D'Ascendis also used risk premium models (RPM) to derive an estimated ROE. However, the parties' inputs in the models resulted in different estimates for ROE. OPC argued that both the DCF and CAPM models employed by OPC witness Woolridge and TECO witness D'Ascendis are market-based approaches to calculating a regulated public utility's fair rate of return, and as such, the methodologies are generally recognized as being consistent with the market-based standards of a fair return contemplated by *Hope* and *Bluefield*. We agree and find that the authorized ROE should be determined using widely accepted cost of capital models and TECO's comparable risk factors. Accordingly, our decision is based on the results of these models with considerations for adjustments due to the things such as flotation costs and company specific risks.

All intervenors argued that TECO should receive a lower ROE based on recent trends. OPC argued that recently, national electric companies have been earning ROEs in the range of 9.00 to 10.00 percent while still having strong investment-grade credit ratings, stocks that sell over book value, and they can raise abundant amounts of capital. FEA argued that all intervenors

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[41] The utility proxy group includes Alliant Energy Corporation, Ameren Corporation, American Electric Power Corporation, Duke Energy Corporation, Edison International, Entergy Corporation, Evergy, Inc., IDACORP, Inc., North Western Corporation, OGE Energy Corporation, Pinnacle West Capital Corporation, Portland General Electric Company, Southern Company, and Xcel Energy, Inc. In his rebuttal testimony, witness D'Ascendis added PNM Resources, Inc. to his original proxy group of fourteen electric companies without explanation. However, the addition of PNM Resources, Inc. did not materially change the average results of his cost of equity models in his rebuttal testimony.

[42] Witness Woolridge also used his own proxy group in addition to that selected by TECO witness D'Ascendis that differed slightly from that used by the other two witnesses.

in this case either agree that TECO’s ROE should be below 9.80 percent or did not present a position on the ROE, and its witness Walters testified that electric and gas ROEs have declined in the last ten years and have been below 10.00 percent for the past nine years. Similarly, FIPUG offered testimony that TECO’s proposed ROE of 11.50 percent is excessive when compared to the 9.78 percent ROE authorized by state regulatory commissions in rate cases decided in 2023 and 2024 for vertically integrated IOUs even though Florida electric IOUs are not riskier and that because Florida is viewed as a very constructive regulatory environment for IOUs, it translates into lower risk for investors.

FRF argued interest rates have already begun to decline and are projected to decline further such that TECO's required ROE is not as great as it was in 2023 or 2024, thus, the absolute maximum ROE that the Commission should even consider is 10.20 percent. Although witness Chriss admitted that the Commission is not bound by decisions of other state regulatory commissions, he asserted that TECO’s requested ROE of 11.50 percent is excessive when compared to broader electric industry trends. FRF noted that 100 basis points of ROE would have an impact of approximately $63.19 million per year on TECO’s revenue requirement. In sum, FRF recommended the Commission should find that an ROE of 9.50 percent, premised on an equity ratio of 54.00 percent, is fully justified by the preponderance of the evidence recorded in this case.

FL Rising/LULAC witness Rábago contended that TECO’s allowed ROE should not exceed the average ROE awarded to other companies, including other Emera companies, and therefore, the Commission should award TECO a midpoint ROE of no higher than 9.50 percent. Witness Rábago asserted that TECO’s ROE proposal is out of step with awarded ROEs in recent years based on a report from the Edison Electric Institute which found awarded ROEs from 2017 to 2022 have averaged 9.52 percent. Witness Rábago further asserted that awarded ROEs over the past ten years have been only slightly higher, at 9.67 percent.

TECO witness D’Ascendis rebutted the recommendations by FIPUG witness Pollock and FRF witness Chriss to use historical authorized ROEs to set TECO’s ROE. He testified that while authorized ROEs may be reasonable benchmarks of acceptable ROEs, they do not reflect the current cost of common equity. We agree that historical authorized ROEs do not reflect the investor-required return at the time the rate case is decided, nor are they are based on market data presented in an evidentiary record.

Walmart argued TECO’s authorized ROE should be no higher than 9.78 percent. Walmart stated that TECO witness Collins testified that through the Company’s currently approved ROE of 10.20 percent, TECO had sufficient capital to make all the needed investments, including O&M expenditures, through the 2021 Settlement Agreement term. Walmart also argued that TECO’s proposed ROE of 11.50 percent is excessive in comparison to the broader national average of authorized ROEs as set forth in FRF witness Chriss’ testimony. In addition, five other intervenor witnesses all testified that TECO’s ROE should be between 9.50 percent and 9.78 percent. Walmart recognized we do not have to consider the ROEs approved by other Commission’s nationwide but suggested we consider what we approved for other Florida utilities.

2. Analysis

TECO witness D'Ascendis, OPC witness Woolridge, and FEA witness Walters all agree that the landmark U.S. Supreme Court *Hope* and *Bluefield* decisions established standards for setting a fair rate of return for equity investment in utilities providing service to the public. Under the *Hope* and *Bluefield* decisions, the U.S. Supreme Court established that a fair rate of return should be comparable to returns on investments in other enterprises having similar risks, sufficient to assure confidence in the financial integrity of the utility, support reasonable credit quality, and allow a company to raise capital at reasonable costs and terms. The Supreme Court defined the ratepayer/investor balance as a reasonably sufficient return to assure confidence in the finances of the utility and should be adequate to support its credit and enable it to raise the necessary money for the proper discharge of its public duties.

This Commission has previously approved the use of multiple cost of equity models that satisfy the terms for determining a fair rate of return as laid out by *Hope* and *Bluefield*. In particular, this Commission recognized the market-based approaches such as the DCF model and the CAPM as being consistent with the market-based standards of a fair return. Nothing mandates the awarded ROE be tied to the result of a particular financial model, and we will establish a reasonable ROE that is consistent with the *Hope* and *Bluefield* decisions. This Commission has a long history of establishing an ROE midpoint and a range of 100 basis points on either side to create a range of reasonableness and ensure rate stability that we continue here.[43]

Section 366.06(2), F.S., charges the Commission to consider whether the utility's rates are insufficient to yield reasonable compensation for the services rendered or that such rates yield excessive compensation for services rendered, and if the rates are either insufficient or excessive, the Commission is to determine the just and reasonable rates to be charged for the utility's service. To the same effect and result, Section 366.07, F.S., provides that whenever the Commission finds that the "rates . . . charged or collected by any public utility for any service . . . are unjust, unreasonable, insufficient, excessive, or unjustly discriminatory," the Commission is to "fix the fair and reasonable rates . . . to be imposed . . . in the future." The Florida Supreme Court recognized the balance between utility interests and customer interests, and the resolution that rates are to be neither insufficient for the utility nor excessive for its customers, in *United Tel. Co. v. Mayo*, 345 So. 2d 648, 653 (Fla. 1977), where the Court stated:

> The rate of return which public utility companies may be allowed to earn is a question of vital importance to both rate payers and investors. . . . That return cannot be set so low as to confiscate the property of the utility, nor can it be made so high as to provide greater than a reasonable rate of return, thereby prejudicing the consumer.

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[43] Order No. PSC-2023-0177-FOF-GU, Issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas,* p 40.

We considered the arguments and testimony of OPC, FRF, and FEA, as well as the rebuttal testimony from TECO. Witness D'Ascendis agreed with witness Chriss that we should consider TECO's use of a future test year and cost recovery mechanisms, and that TECO's risk profile under the *Hope* and *Bluefield* standard requires the allowed ROE to be commensurate with the returns on investment of similar risk with the proxy group of electric companies.

As such, we find that the authorized ROE should be determined using widely accepted cost of capital models and TECO's comparable risk factors. Emera Inc.'s credit profile should not have a bearing on TECO's authorized ROE in Florida. Accordingly, we discuss the results of each witnesses' Cost of Equity Models, noting any adjustments made or models omitted in arriving at our own final calculations.

a. Cost of Equity Models

1. Discounted Cash Flow Model

No party disputed the use of the DCF model in general, which is based on the theory that a stock's current price represents the present value of all expected future cash flows in the form of dividends discounted at the appropriate risk-adjusted rate of return.[44] The controversy is over the inputs into the model. TECO witnesses D'Ascendis and OPC witness Woolridge used an adjusted version of the single-stage constant growth DCF model by adjusting the annual dividend for expected growth expressed as: ROE = [(dividend (1 + 0.5growth rate)) ÷ stock price] + growth rate. FEA Witness Walters adjusted the dividend by the full value of the growth rate in his DCF calculation to adjust the dividend upwards. We agree with the witnesses' use of an adjusted DCF model to account for growth in dividend payments from the utilities. Although witness D'Ascendis acknowledged that DCF theory calls for using the full growth rate, he and OPC witness Woolridge used one-half the growth rate in their DCF calculations because the utilities in the proxy group increase their quarterly dividends at various times of the year. We agree this is a reasonable and conservative assumption as not all companies increase their dividends at the same time of year, the dividends should reflect the next twelve-month period, and this approach should help prevent overstating the dividend yield, as explained by TECO witness D'Ascendis.

TECO witness D'Ascendis' DCF model results for each of the companies in his utility proxy group ranged from 8.21 percent to 11.52 percent with an average of 10.16 percent. The average dividend yield for witness D'Ascendis' proxy group was 4.42 percent with an average growth rate of 6.01 percent. Witness D'Ascendis growth rate of 6.01 percent is based on an average of five-year forecasts of earnings per share (EPS) from three publicly available sources of published analysts' estimates from Value Line, Zacks, and Yahoo! Finance, and he explained investors are likely to rely on widely available financial information services.

[44] In its basic form, the DCF model is expressed as the dividend yield of a stock plus the expected long-term growth rate. Expressed mathematically as: ROE = (dividend ÷ stock price) + growth rate. This is known as the traditional single-stage constant growth DCF model.

OPC witness Woolridge's DCF model results from his proxy group of 24 companies was 9.70 percent, and using TECO witness D'Ascendis' proxy group, his result was 10.00 percent. For the dividend yield, witness Woolridge used the current annual dividend and the 30, 90, and 180-day average stock prices. Witness Woolridge's growth rates for both proxy groups were obtained from the average of the projected sustainable growth rate based on the average of the projected EPS, dividends per share (DPS), and book value per share growth rates from Value Line of 5.00 percent, and the projected EPS growth rates of Wall Street analysts of 5.95 percent. The average of OPC witness Woolridge's two DCF models was 9.85 percent.

FEA witness Walters applied three different DCF models to TECO witness D'Ascendis' proxy group to estimate TECO's ROE. Witness Walters used the single-stage constant growth model using analyst growth rates in his first model and sustainable growth rates in his second model. Witness Walters explained the sustainable growth rate, also referred to as the internal growth rate, is determined by the proportion of the utility's earnings that is retained and reinvested in its plant and equipment. The earnings grow as the plant, funded by the reinvested earnings, is put into operation, allowing the utility to receive its authorized return on the additional rate base investment. In his third DCF model, witness Walters applied a multi-stage model that uses three growth stages that reflect a reasonable expectation of a shift in growth from an initial high growth period, to a transition period, followed by a long-term growth period extending into perpetuity.

For his constant growth DCF model using analyst's EPS forecasts, FEA witness Walters calculated an adjusted dividend yield of 4.65 percent. For his growth rate of 6.33 percent, he relied on the average of professional securities analyst's projected EPS growth estimates from three publicly available sources: Zacks, S&P Capital IQ Market Intelligence, and Yahoo! Finance. The DCF results for his constant growth DCF model using security analyst EPS estimates was 10.98 percent which is significantly higher than TECO witness D'Ascendis' DCF average result of 10.16 percent. There are several reasons for witness Walter's higher result. First, he included an outlier ROE result of 15.77 percent in his proxy group which witness D'Ascendis excluded because it was too high.[45] Eliminating that result from witness Walters' DCF result lowers his average to 10.61 percent. Second, witness Walters adjusted the dividend yield for each company by the full amount of the growth rate as opposed to only one-half the growth rate as did TECO witness D'Ascendis and OPC witness Woolridge. Removing the DCF model result from Portland General Electric Company and applying a one-half the growth rate to adjust the dividend yield reduces witness Walters' DCF result using analyst forecasts by 50 basis points from 10.98 percent to 10.48 percent. We find this adjusted result of 10.48 percent is more reasonable and is more comparable with the approach used by witness D'Ascendis and witness Woolridge and we have incorporated it into our own calculation.

For his second DCF model analysis using a sustainable growth rate, FEA witness Walters calculated a dividend yield of 4.58 percent, and an average growth rate of 4.80 percent for an average result of 9.70 percent. For his third DCF model analysis, witness Walters' applied a multi-stage DCF methodology and obtained a result of 9.35 percent. In his multi-stage DCF

[45] Portland General Electric Company

model, witness Walters' estimated a growth rate of 6.33 percent in the first 5-year stage of growth, followed by a declining growth rate in years 6 through 10 from 5.97 percent to 4.51 percent, and a terminal growth rate of 4.14 percent. Overall, the average results from witness Walters' three DCF analysis ranged from 9.35 percent to 10.98 percent, with an average of 9.90 percent.

Each witness advocated for the use of their own particular inputs and assumptions, at times attacking those of the other witnesses, and many of those arguments were in turn refuted in rebuttal testimony. We find merit in each of the witness' approaches and therefore, we find equal weight should be given to all three of the witnesses' DCF model results using growth rates from analysts' forecasts and the sustainable growth rate. Further, TECO witness D'Ascendis' argument that the Commission should only consider the DCF model using analyst forecasted growth rates was not convincing and contradicted his own opinion that the Commission should consider multiple cost of equity models. Therefore, we find an appropriate approach is to give equal consideration to the results from all three witnesses DCF analyses except for FEA witness Walters' multi-stage application. We agree with witnesses' D'Ascendis that the multi-stage DCF model is not appropriate for electric utility companies because they are mature firms in the constant growth business cycle.

2. Capital Asset Pricing Model

The CAPM is a market-based model that estimates the cost of equity for a stock as a function of a risk-free return plus a market risk premium (MRP).[46] The basic CAPM equation requires only three inputs to estimate the cost of equity: (1) the risk-free rate; (2) the beta coefficient; and (3) the MRP expressed in this equation: ROE = risk-free rate + Beta (market return – risk-free rate). TECO witness D'Ascendis used two variations of the CAPM, the traditional CAPM and the Empirical CAPM or ECAPM. We have omitted consideration of the ECAPM as duplicative of the traditional CAPM.

i. Risk-Free Rate

The three cost of capital witnesses used three different methods to estimate the risk-free rate used in their CAPM analysis. TECO witness D'Ascendis used the average of the consensus forecasts for the yields on the 30-year U.S. Treasury bonds for the six quarters ending with the third calendar quarter of 2025, and long-term projections for the years 2026 to 2030 and 2031 to 2038 as published in the May 31, 2024, Blue Chip Financial Forecast. His estimate was 4.41 percent. OPC witness Woolridge's risk-free rate is based on the historical yields on 30-year U.S. Treasury Bonds from January 1, 2010 to May 1, 2024. Witness Woolridge testified that the current 30-year Treasury yield is in the 4.50 percent to 4.75 percent range and he chose 4.65 percent as the risk-free rate to use in his CAPM analysis. FEA witness Walters used the

[46] The market risk premium is defined as the incremental return of the stock market as a whole less the risk-free rate multiplied by the beta for the individual security. The beta is expressed as the volatility of an individual security compared against the stock market as a whole. A beta value of 1.0 indicates the individual security has the same volatility as the stock market. A beta value of less than 1.0 is considered less risky than the stock market as a whole and a beta value greater than 1.0 is considered more risky.

projected yield on the 30-year Treasury Bond for the second and third quarters of 2025 of 4.20 percent as published in the May 1, 2024, Blue Chip Financial Forecasts.

ii. Beta Coefficient

TECO witness D'Ascendis used the betas published by Value Line and Bloomberg. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of the beta to regress to the market mean of 1.00, Value Line calculates the beta over a five-year period, while Bloomberg calculates it over a two-year period. For each company in his proxy group, witness D'Ascendis averaged the Value Line and Bloomberg beta values and then averaged the company averages to arrive at an overall beta of 0.81 for his proxy group. OPC witness Woolridge used betas published by Value Line and S&P Capital IQ. Witness Woolridge made an upward adjustment using the Blume adjustment to the S&P betas. Witness Woolridge averaged the two beta measures for each of the companies and then averaged all the companies' average betas for a proxy group average. Witness Woolridge calculated an average beta of 0.81 for his proxy group and 0.82 for the D'Ascendis proxy group. FEA witness Walters used three different betas in the nine iterations of his CAPM analysis. He used the current betas published by both Value Line and S&P Global Market Intelligence, and the average of the historical betas over the period from the third quarter of 2014 to the fourth quarter of 2023 as provided by Value Line Investment Survey. His results were 0.92 for the current Value Line beta, 0.85 for the current S&P beta, and 0.76 for the historical beta.

iii. Market Equity Risk Premium

The Market Equity Risk Premium (MRP) is an estimate of the required return on the stock market less the estimated risk-free rate. In his rebuttal testimony, TECO witness D'Ascendis derived a MRP of 8.93 percent based on the average of three historical data-based market risk premiums, two Value Line data-based market risk premiums, and one using Bloomberg data. TECO witness D'Ascendis' average MRP result was 8.82 percent, excluding his derivation using his PRPM applied to Kroll Historical Data. Witness D'Ascendis' estimated MRP of 8.82 indicates the expected return on the market going forward is 13.23 percent (8.82% + 4.41%). OPC witness Woolridge based his MRP estimate on his review of 19 academic and professional studies dated after January 2, 2010 that discuss and estimate the MRP. Witness Woolridge testified that the studies suggest that the appropriate MRP is within the range of 4.00 percent to 6.00 percent. Witness Woolridge gave the most weight to the market risk-premium estimates provided by Kroll, KPMG, JP Morgan, Damodaran, Fernandez, and Duke-CFO surveys. Witness Woolridge concluded a MRP in the 5.00 percent to 5.50 percent range is appropriate and used the midpoint of this range, 5.25 percent, as his MRP in his CAPM analysis.

FEA witness Walters' MRP estimates were derived using both a risk premium approach and a DCF approach. Witness Walters also used the normalized market risk premium of 5.50 percent with the normalized risk-free rate of 4.61 percent as recommended by Kroll. To calculate a MRP using a risk premium method, witness Walters used the historical, arithmetic-average, real-market return over the period 1926 to 2023 using data from Morningstar Direct. The arithmetic-average real return on the market since 1926 was 9.02 percent. Witness Walters added the current consensus for projected inflation, as measured by the Consumer Price Index of 2.40 percent to derive an expected market return of 11.64 percent. The MRP is the difference between the 11.64 percent expected market return and the projected risk-free rate of 4.20 percent, or 7.44 percent. Witness Walters also employed two versions of the constant growth DCF model to develop his MRP estimates: the Federal Energy Regulatory Commission's (FERC) method of estimating the expected return on the market and an alternative version of the FERC DCF method using all companies in the S&P 500 Index rather than just dividend paying companies.[47] Witness Walters' expected market return using the FERC DCF model was 12.70 percent and using the alternative DCF model was 12.69 percent. The DCF model MRP result was the expected market return of 12.70 percent, less the projected risk-free rate of 4.20 percent, or 8.50 percent. Overall, witness Walters estimated three different MRPs of 5.50 percent, 7.44 percent, and 8.50 percent, which averaged 7.15 percent.

The average results of TECO witness D'Ascendis' application of the CAPM is 11.58 percent. We have excluded witness D'Ascendis' ECAPM results as duplicative and only serving to bolster the overall CAPM result. OPC witness Woolridge used the traditional form of the CAPM to calculate a cost of equity of 8.85 percent for both his proxy group and witness D'Ascendis' proxy group. FEA witness Walters applied nine different iterations of the CAPM to witness D'Ascendis proxy group. The results ranged from 8.80 percent to 12.03 percent. The average of his nine results is 10.36 percent.

While again, each witness advocated for the use of their own inputs and assumptions, at times attacking the approach taken by other witnesses, we find that each of the approaches taken by these witnesses has merit and the best approach to accounting for them is to take the average. The average of all three witnesses' traditional CAPM results is 10.26 percent ((11.58% + 8.85% + 10.36% = 30.87) ÷ 3 = 10.26%).

3. Risk Premium Model

The Risk Premium Model (RPM) theory recognizes that common equity capital has a greater investment risk than debt capital, and as a result, investors require higher returns on common stocks than bonds to compensate them for bearing the additional risk. Therefore, the cost rate of common equity can be derived by calculating the spread between bonds and the estimated required return on equity of investors.

TECO witness D'Ascendis used three separate RPM methodologies in what he called his Total Market Approach RPM (TMARPM). Within witness D'Ascendis' TMARPM, he added a prospective public utility bond rate to the average of three separate equity risk premium estimates. Witness D'Ascendis based his three equity risk premiums estimates on: (1) a beta-adjusted total market analysis using five estimates of the spread between projected market returns and A-rated corporate bonds; (2) the spread between Moody's A2 rated public utility

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[47] FERC's method for estimating the expected return on the market is to perform a constant growth DCF analysis on each of the dividend-paying companies of the S&P 500 index. The dividend yield is adjusted by (1+ 0.5g) and the growth rate component is based on the average of the growth projections excluding companies with growth rates that were negative or greater than 20 percent.

bond yields and the return on the S&P Utilities Index holding period returns; and (3) a regression analysis of the awarded ROEs in 1,237 fully-litigated electric rate cases as compared to Moody's A2-rated public utility bond yields. The average of those three risk premium estimates was 5.27 percent. Witness D'Ascendis added his estimated risk premium of 5.27 percent to his estimated prospective utility bond yield of 5.80 percent that reflects the bond rating of the proxy group based on a Moody's long-term issuer rating of Baa1. Witness D'Ascendis' RPM analysis result was 11.07 percent (5.27% + 5.80%).

OPC Witness Woolridge testified, and we agree, that witness D'Ascendis' estimate of the average expected stock market return of 15.60 percent used to calculate a market risk premium of 11.45 percent is excessive and unrealistic. The EPS growth rate projection (14.10 percent) used for the S&P 500 and the resulting expected market return (15.60 percent) and market risk premium (11.45 percent) includes unrealistic assumptions regarding future economic and earnings growth and stock returns.

FEA witness Walters opined that TECO witness D'Ascendis' average estimates of the equity risk premium under the prospective bond yield and spot yield approaches using the TMARPM are the results of individual estimates. When each equity risk premium result is considered in isolation, it is clear to see that the overwhelming majority of his results are in excess of any reasonable estimate. For example, if we look at witness D'Ascendis' twelve estimates of the equity risk premium, they would produce a risk premium result in the range of 10.00 percent to 16.02 percent. Considering the lowest estimate based on his risk premium analysis starts at 10.00 percent is indicative that almost all of his risk premium results are excessive in light of where recent authorized ROEs for electric utilities has been recently. When individual results are looked at in isolation, it is clear that they produce excessive results that are unreliable. Five of witness D'Ascendis' RPM results range from 11.69 percent to 16.02 percent. These estimates are so far removed from observable benchmarks such as the allowed ROEs recently awarded to similar utilities, that it is hard to conclude these results are based on reasonable methods of estimation, and we have therefore excluded them.

FEA witness Walters' RPM methodology compared the difference between regulatory commission-authorized returns on common equity and contemporary U.S. Treasury Bonds and contemporary Moody's A-rated and Baa-rated utility bond yields. Overall, witness Walters produced five estimates of the equity risk premium as compared to regulatory commission authorized ROEs for electric utilities on an annual basis for each year since January 1986 until 2023. The authorized ROEs ranged from 13.93 percent in 1986 to 9.39 percent in 2021, with an average of 10.84 percent. Witness Walters explained that he selected the period 1986 through 2023 because public utility stocks consistently traded at a premium to book value during that period, and the market-to-book ratio for the utility industry was consistently above a multiple of 1.0. Witness Walters asserted that over this period, an analyst can infer that authorized ROEs were sufficient to support market prices that at least exceeded book value, supported a utility's ability to issue additional common stock without diluting existing shares, and demonstrates that utilities were able to access equity markets without a detrimental impact on current shareholders.

To derive his equity risk premium using Treasury Bond yields, witness Walters' quantified the difference between regulatory commission-authorized returns on common equity (10.84 percent) and contemporary U.S. Treasury bonds (5.14 percent). The difference between the authorized return on common equity and the Treasury bond yield is a risk premium of 5.70 percent. (10.84% – 5.14% = 5.70%). Adding the equity risk premium of 5.70 percent to the projected 30-year U.S. Treasury Bond yield of 4.20 percent obtained from Blue Chip Financial Forecasts yields an indicated ROE of 9.90 percent. Witness Walters also derived equity risk premiums using A-rated and Baa-rated utility bonds as published by Moody's. For his estimate of the bond yields, witness Walters used the 13-week average from February 16, 2024 through May 10, 2024, and the 26-week average from November 17, 2023, through May 10, 2024, for both the A-rated and Baa-rated utility bond yields.

To derive his equity risk premium over utility bonds, he subtracted the average A-rated utility bond yield of 6.50 percent from the authorized ROEs of 10.84 percent which resulted in an estimated equity risk premium of 4.34 percent. Adding the 4.34 percent equity risk premium to the 13-week average A-rated utility bond yield of 5.66 percent resulted in an indicated ROE of 10 percent. The 13-week average of the Baa-rated utility bond yield was 5.89 percent and resulted in an indicated ROE of 10.23 percent (4.34% + 5.89%). Over the 26-week period, the A-rated utility bond yield averaged 5.60 percent while the Baa-rated utility bond yield averaged 5.84 percent. Adding the equity risk premium of 4.34 percent to the 26-week average A-rated utility bond yield of 5.60 percent and the Baa-rated utility bond yield of 5.84 percent, produced indicated ROEs of 9.94 percent, and 10.18 percent, respectively. Witness Walters gave primary consideration to his RPM using Treasury Bonds and A-rated utility bonds. The average of those results was 9.95 percent. However, we disagree with the weight placed on the lower results. By witness Walters's analysis, the average credit rating of the proxy group reflects a Moody's credit rating of Baa2, and therefore, RPM results using the Baa-rated utility bond yields should be given equal weight. The simple average of witness Walters' five RPM results is 10.05 percent.

TECO witness D'Ascendis derived an estimated ROE of 11.07 percent (excluding the PRPM) using the average of the results of three different RPMs. FEA witness Walters used two RPM analyses based on historical commission-authorized returns on common equity as compared to Treasury Bonds and A-rated and Baa- rated Utility Bonds. Witness Walters RPM results ranges from 9.90 percent to 10.23 percent, with an average of 10.05 percent. OPC witness Woolridge did not use a RPM analysis in his testimony because he believed that risk-premium studies, of which the CAPM is one form, provide a less reliable indication of equity-cost rates for public utilities and primarily relied on the DCF model to estimate the cost of equity. The average of TECO witness D'Ascendis and FEA witness Walters RPM results was 10.56 percent.

A summary of all of the models submitted for our consideration is contained in Table 10.

Table 10
Summary of Cost of Equity Model Results

ROE Model	TECO – D'Ascendis	OPC - Woolridge	FEA - Walters
DCF – with analyst growth estimates	10.16%	Did not apply	10.98%
DCF – with sustainable growth estimates	Did not apply	9.70% / 10.00%* *D'Ascendis Proxy Group	9.37%
DCF – Multi-Stage growth rates	Did not apply	Did not apply	9.35%
CAPM	11.91%	8.85% (for both proxy groups)	9.29% - 11.43%
Risk Premium	11.09%	Did not apply	9.90% - 10.23%
Range of Results	10.29% - 11.91%	8.85% - 10.00%	9.29% - 11.43%
Average of Results	11.09%	9.28% / 9.43%* *D'Ascendis Proxy Group	10.07%
Witness Recommended ROE	11.50%	9.50%	9.60%

b. Flotation Costs

TECO witness D'Ascendis made an upward adjustment of 10 basis points to the results of his ROE analyses to reflect the effect of flotation costs. Witness D'Ascendis testified that all of the cost of equity models assume no transaction costs and those costs are not reflected in the market prices paid for common stocks.

Flotation costs are those costs associated with the sale of new issuances of common stock. They include the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the company receives less than one full dollar in financing. To calculate a flotation cost allowance, witness D'Ascendis modified his DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with a method that is supported in academic literature. The flotation cost adjustment calculated by witness D'Ascendis recognizes the actual costs of issuing equity that were incurred by TECO's parent, Emera, in its equity issuances since its acquisition of TECO based on Emera's actual issuance costs.

OPC witness Woolridge disagreed that a flotation cost adjustment is justified in this case and testified that there is no evidence that TECO has paid flotation costs and hence, TECO should not receive higher revenues for flotation costs that the Company did not incur. OPC witness Woolridge asserted that TECO witness D'Ascendis' comparison of flotation costs to the amortization of bond flotation costs is not correct. Witness Woolridge argued that, if anything, there should be a cost reduction and not an increase. He further contended that flotation costs consist primarily of the underwriting spread, or the difference between the price the bank receives from investors and the price the bank pays to the company, and not out-of-pocket expenses, and therefore should not be recovered through the regulatory process. Witness Woolridge asserted that the underwriting spread is known to the investors who are buying the new issue of stock, and thus, the offering price is what is material to the decision to purchase the stock based on the expected return and risk prospects, and any flotation costs are reflected in the price of the stock.

In Order No. PSC-2023-0388-FOF-GU, the Commission found that witness D'Ascendis method to determine the flotation cost for Peoples Gas System, Inc., also a subsidiary of Emera, is credible and provided persuasive evidence for his recommendation to include a flotation cost.[48] This Commission has a long-standing policy to recognize flotation costs in the cost of equity models used to estimate the ROE for utilities. We find witness D'Ascendis' method to determine the flotation cost is credible and supports his recommendation to include a flotation cost of 10 basis points. Our leverage formula makes a similar adjustment to the DCF Model and also adds 20 basis points to the CAPM result to recognize flotation costs.[49] Ultimately, we find the record evidence in this case demonstrates that TECO witness D'Ascendis calculated a reasonable estimate for flotation costs that should be recognized in the estimated cost of equity.

c. Company Specific Business Risks

TECO witness D'Ascendis asserted that TECO is subject to certain business risks not applicable to the companies in his proxy group. To reflect TECO's specific business risks, witness D'Ascendis considered TECO's size relative to the utility proxy group, lack of geographic diversification, and higher climate risk relative to the utility proxy group. Witness D'Acsendis also considered TECO's high customer growth and increased capital expenditures. Witness D'Ascendis concluded that TECO is similar in size to the utility proxy group companies based on market capitalization and a relative risk adjustment due to size is not necessary in this proceeding.

Witness D'Ascendis asserted that TECO's lack of geographic diversity increases its relative risk. Witness D'Ascendis testified that TECO's service area in West Central Florida is extremely compact compared to other Florida investor-owned utilities as well as the companies in his proxy group. Witness D'Ascendis explained that in the event of a substantial storm or other catastrophic event the entire system and customer base of TECO is at risk for damage, outages, and other customer impacts. This is unlike other utilities in Florida as well as the proxy group which have more geographically diverse service areas or larger service territories. A larger service territory may only have a portion of a utilities' infrastructure and customers impacted which can help mitigate the impacts and help sustain the utility while repairs are made in the affected areas. TECO's smaller geographic diversity has also been recognized as a key risk in the company's recent S&P and Moody's credit ratings reports. Witness D'Ascendis testified that Moody's noted that it views the Commission's regulatory treatment of storm costs as credit supportive, it also stated that "Tampa Electric is a relatively small utility with a concentrated service territory along the Gulf Coast of western central Florida, making it vulnerable to storm related event risk." Witness D'Ascendis also testified that S&P similarly noted that "[Tampa

[48] Order No. PSC-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System, Inc.,* p. 68.
[49] Order No. PSC-2024-0165-PAA-WS, issued May 22, 2024, in Docket No. 20240006-WS, *In re: Water and wastewater industry annual reestablishment of authorized range of return on common equity for water and wastewater utilities pursuant to Section 367.081(4)(f), F.S.*

Electric's] service territory is more susceptible to physical risks related to hurricanes," and also finds that "[r]elative to peers, physical risks associated with coastal storms are evident."

Additionally, witness D'Ascendis testified that Hillsborough County, which includes the majority of TECO's customers, is ranked 15th in the Federal Emergency Management Agency's National Risk Index. That ranking measures the potential for negative effects of naturally occurring hazards and is driven by the expected annual loss of value associated with hurricanes of all counties in the U.S. Witness D'Ascendis asserted that TECO's risk associated with extreme weather events is relatively high as compared to the utility proxy group. Witness D'Ascendis also testified that TECO's storm reserve doesn't entirely insulate the Company from the risks associated from hurricanes. Witness D'Acsendis asserted that TECO's ability to recover storm costs by petitioning the Commission outside of a rate case doesn't mitigate the risk of regulatory lag, especially for significant storms with costs over $100 million. For example, TECO's storm related costs incurred in September and November 2022 will not be fully recovered until December 2024. Furthermore, the increased frequency of hurricanes and other large storms will only serve to increase restoration costs and the need to recover those costs. Witness D'Ascendis testified that TECO faces relatively higher risk from extreme weather events as compared to the proxy group. Witness D'Ascendis contended that although TECO has the ability to utilize a storm reserve and petition this Commission to recover additional restoration costs above the reserve level, that regulatory framework does not eliminate the risk faced by the Company. As such, TECO's relatively higher risk associated with extreme weather is unique to the Company as compared to the proxy group and supports an upward adjustment when determining the appropriate ROE in this proceeding.

d. Capital Investment and Customer Growth

In addition to TECO's flotation costs, relative credit rating, and its smaller relative size, witness D'Ascendis also considered TECO's high customer growth and level of capital expenditures as compared to his proxy group. Witness D'Ascendis asserted that TECO's strong customer growth over the past five years necessitates increased and accelerated capital investment. Witness D'Ascendis testified that TECO currently plans to invest over $6.2 billion of additional capital over the 2024-2027 period, which represents over 68 percent of its 2022 year-end net utility plant. That amount includes investments required to support growth, and to maintain safe, sufficient, and reliable service in both its transmission and distribution facilities. As discussed by TECO witness Chronister, the Company will require continued access to the capital markets, at reasonable terms, to finance its capital spending plan. Witness D'Ascendis testified that credit rating agencies recognize risk associated with increased capital expenditures. From a credit perspective, the additional pressure on cash flows associated with high levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings.

Witness D'Ascendis also compared TECO's expected capital expenditures to the companies in his proxy group. Witness D'Ascendis calculated TECO's ratio of expected capital expenditures to net plant and compared that ratio to the ratio for each company in his proxy group. Witness D'Ascendis determined that TECO had the highest ratio of projected capital expenditures to net plant relative to the proxy group, approximately 26 percent higher than the proxy group median. Witness D'Ascendis did not make a quantitative adjustment to the results of his cost of equity models to reflect TECO's company specific business risks. He simply "considered" TECO's relatively small service area, weather risk, high customer growth, and the Company's capital expenditure program in his determination of the appropriate ROE within the range of the results of his cost of equity models. The range of witness D'Ascendis' updated cost of equity models is 10.29 percent for the DCF model to 11.91 percent for the CAPM. His recommended ROE of 11.50 percent is above the median of 11.10 percent for his range of results to reflect the company specific risks – a difference of 40 basis points.

e. Financial Risk

Financial risk is created by the introduction of debt into the capital structure. The higher proportion of debt in the capital structure the greater the financial risk. Consistent with the basic principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk. There is a direct correlation between the amount of debt in a utility's capital structure and the financial risk that an equity investor will associate with that utility. On cross-examination TECO witness D'Ascendis agreed that a relatively lower proportion of debt translates into a lower required return on equity, all other things being equal. OPC witness Woolridge asserted and we agree that the fundamental relationship between lower risk and the appropriate authorized return should not be ignored.

TECO requested, and we have approved, an equity ratio of 54.00 percent which is higher than the average equity ratio witness D'Ascendis' proxy group and witness Woolridge's proxy group. The mean average five-year common equity ratios for the proxy companies and their operating subsidiaries are 43.25 percent and 49.05 percent, respectively. In addition, the average common equity ratios for the parent holding companies in the two proxy groups as of December 31, 2023, were 40.90 percent for witness Wooldridge's proxy group and 40.10 percent for witness D'Ascendis' proxy group. These averages clearly are materially lower than TECO's proposed common equity ratio of 54.00 percent, which demonstrate that TECO has less financial risk than the proxy groups used by the witnesses to estimate the ROE for TECO.

Witness D'Ascendis included a downward credit risk adjustment of 8 basis points (0.08 percent) to recognize TECOs higher long-term debt rating as compared to the average bond ratings of his proxy group. Witness D'Ascendis' credit risk adjustment is based on debt/credit ratings and did not recognize the actual difference in the amount of debt included in the regulatory capital structure of TECO which the record demonstrates is considerably less than the average of the proxy groups. This financial risk must be recognized when setting the ROE for ratemaking purposes. Witness D'Ascendis agreed that the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks.

2. Conclusion

TECO witness D'Ascendis testified that we should continue our precedent when setting the ROE and follow the models, because the models are what represents the market. Witness D'Ascendis explained, "The outcomes of rate cases are results of things like this [cost of equity models], where I am putting the -- I have my number, Dr. Woolridge has his number, Mr. Walters has his number, and it's up for the Commission and the Commission staff to kind of balance those interests." The collective range of the witnesses' cost of equity model results is 8.85 percent to 11.91 percent. The average of the DCF model results, CAPM results, and RPM results for TECO's, OPC's, and FEA's witnesses are 9.98, 10.26, and 10.56 percent, respectively. The average of the results of the three cost of equity model results is 10.27 percent.

Record evidence supports the risk-return concept that utilities with lower financial risk should be awarded lower returns. The record evidence demonstrates TECO has a higher equity ratio than the average of the electric utility company proxy group, and as such, it has less financial risk. Therefore, a downward adjustment to TECO's ROE should be recognized to reflect TECO's lower financial risk as compared to the electric company proxy group. The record evidence also supports upward adjustments for TECO's higher business risk and its flotation costs. We find TECO's lower financial risk does not entirely offset TECO's higher business and weather risk nor its flotation costs, and an additional adjustment to the average results of the models is therefore appropriate. In addition, the record evidence is clear that interest rates have increased since TECO's last rate case in 2021 in which we authorized an ROE of 9.95 percent, later adjusted to 10.20 percent. Therefore, we find the record evidence supports an ROE of 10.50 percent for TECO, which will enable TECO to generate the cash flow needed to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, maintain sufficient levels of liquidity to fund unexpected events, and sustain confidence in Florida's regulatory environment among credit rating agencies and investors.

An authorized ROE of 10.50 percent, with a range of 9.50 percent to 11.50 percent, is hereby approved for use in establishing TECO's revenue requirement for the 2025 projected test year.

H. Weighted Average Cost of Capital (Issue 40)

1. Analysis

The capital structure and weighted average cost of capital (WACC) is a fall-out issue that incorporates the amounts and cost rates of the capital sources into a final WACC, also referred to as the overall rate of return. Because of the intervernors' various recommended ROEs, there were various proposed capital structures offered for our consideration. OPC argued TECO's proposed capital structure and WACC should be adjusted to reflect an ROE of 9.50 percent and include zero cost deferred tax credits. FEA argued TECO's capital structure and WACC should be adjusted to reflect an equity ratio of 52.00 percent and an ROE of 9.60 percent. However, we have already addressed the cost rates and amounts of the capital components in our resolution of Issues 33 through 39, and the intervenors' proposed capital structures are inconsistent with our rulings on those issues.

In MFR Schedule D-1a, page 4 of 22, TECO presented its requested projected test year capital structure based on a 13-month average as of December 31, 2025, consisting of common equity in the amount of $4,620,873,000 (54.0 percent), long-term debt in the amount of

$3,557,446,000 (41.6 percent) and short-term debt in the amount of $378,853,000 (4.4 percent) as a percentage of investor-supplied capital. TECO revised the total amount to $9.791 billion, to reflect the adjustments to rate base as described in TECO's August 22, 2024 letter. This adjustment, however, did not materially change the Company's requested WACC. The initial capital structure submitted by TECO is summarized in Table 11. The percentages in the ratio column account for all capital components together, not just the aforementioned investor-supplied capital sources.

Table 11
TECO Recommended Weighted Average Cost of Capital (Dollars in 000's)

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	$4,620,873	46.89%	11.50%	5.39%
Long-Term Debt	$3,557,446	36.09%	4.53%	1.63%
Short-Term Debt	$378,853	3.84%	3.90%	0.15%
Customer Deposits	$99,787	1.01%	2.41%	0.02%
ADITs	$986,702	10.01%	0.00%	0.00%
Investment Tax Credits	$212,932	2.16%	8.26%	0.18%
Total	$9,856,592	100.00%		7.37%

2. Conclusion

Although we considered all of the testimony and evidence on this issue, the intervenors' proposed capital structures are not consistent with our decision in Section VI regarding all other 2025 Cost of Capital related issues. Therefore, we find that a capital structure consisting of an equity ratio of 54.00 percent based on investor sources (as summarized in Table 12) is appropriate.

Table 12
Approved Weighted Average Cost of Capital (Dollars in 000's)

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	$4,583,688	46.89%	10.50%	4.92%
Long-Term Debt	$3,528,800	36.10%	4.53%	1.64%
Short-Term Debt	$375,823	3.84%	3.90%	0.15%
Customer Deposits	$98,984	1.01%	2.41%	0.02%
ADITs	$978,507	10.01%	0.00%	0.00%
Investment Tax Credits	$209,579	2.14%	7.90%	0.17%
Total	$9,775,379	100.00%		6.90%

We therefore approve a capital structure consisting of 54.00 percent common equity, 41.60 percent long-term debt, and 4.40 percent short-term debt as a percentage of investor sources for the 13-month average test year ending December 31, 2025. Furthermore, a weighted average cost of capital of 6.90 percent is approved to establish TECO's projected test year revenue requirement and setting rates in this proceeding.

VII. Net Operating Income

This section addresses issues that relate to TECO's Net Operating Income. These issues were identified as issues 41 to 64 in the Prehearing Order, and include Test Year and Total Operating Revenues (Issue 41 and 42), various O&M Expenses (Issues 43-47), Fuel Adjustments (Issue 48), amongst others.

A. Test Year Revenues (Issue 41)

1. Analysis

This Issue addresses the level of TECO's revenues from the sale of electricity for the 2025 test year. As explained in Issue 2, TECO provided forecast models which detail the Company's forecasted customer counts, energy sales, and demand across the Company's rate classes for the 2025 test year. Once the forecasted customer counts, energy sales, and demand forecasts are established, they are then multiplied by TECO's current rates for each customer class and summed to yield total revenues.

TECO's estimated revenue at current rates, approximately $1.481 billion, is supported by the Company's MFRs and the direct testimony of TECO witnesses Cifuentes and Chronister. TECO argued the resulting test year revenues at current rates of $1.481 billion is reasonable and should be approved by the Commission. On the other hand, OPC witness Dismukes argued that TECO's test year revenues at current rates are understated and should be increased by $12.260 million to account for OPC's proposed increase to TECO's energy sales projection. FL Rising/LULAC, FIPUG, FRF, and Walmart agree with OPC while FEA, Sierra Club, and Fuel Retailers take no position.

TECO contends that OPC's proposed adjustments to test year revenues at current rates are unreasonable and erroneously suggest that the base revenues are understated. Previously, we found TECO's out-of-model adjustments warranted and were not persuaded by the counter arguments raised by OPC. Therefore, we reject OPC's proposed increase of $12.3 million to TECO's test year revenues related to the sales adjustment proposed by OPC witness Dismukes.

2. Conclusion

We find that TECO used the correct current rates for all customer classes in its calculations of test year revenue. No adjustment is necessary to TECO's customers, energy, and demand forecasts as addressed in Issue 2. Therefore, TECO's estimated revenues at current rates of $1.481 billion for the 2025 projected test year is correctly calculated.

B. Total Operating Revenues (Issue 42)

1. Analysis and Conclusion

TECO stated that its projected Total Operating Revenues totaling $1.518 billion are supported by the Company's MFRs and witness Chronister's testimony. TECO argued this amount is reasonable, not challenged by the intervenors, and should be approved by the Commission.

No intervenor challenged TECO's calculation of "other operating" revenue. We find that the appropriate amount of "other operating" revenues, which include miscellaneous service charges, rent from electric property, and other electric revenue at current rates for the projected test year, is $37.746 million. This calculation is supported by the record and is consistent with our decisions on Issues 2 and 41. Thus TECO's stated base revenues shall remain unchanged. When combined with TECO's projected other revenues for the test year of $37.746 million, this results in projected total operating revenues of $1.518 billion for the 2025 test year.

C. Polk 1 Unit O&M Expense (Issue 43)

1. Analysis

Polk Unit 1 is a 220 MW IGCC plant that entered service in 1996. TECO intended to convert the unit to a simple cycle combustion turbine as part of the Polk Flexibility project and retain the remaining IGCC components, including the Gasifier, HRSG, and ST. TECO estimated the non-fuel O&M for Polk Unit 1 to be $9,685,047 in the 2025 projected test year. This is inclusive of expenses needed to maintain the gasifier in long-term reserve status.

Although Sierra Club opposed TECO's Polk Unit 1 project entirely, and therefore argued that TECO should not recover O&M costs associated with the unit, no other intervenor took a position. We find the conversion of Polk Unit 1 to a simple cycle configuration to be cost-effective as further articulated in Issue 24.

TECO offered evidence that the project was cost-effective, but the retirement of the non-simple cycle components of Polk Unit 1 must be reflected in the amount approved. TECO witness Aponte asserted that TECO demonstrated the Polk Flexibility project is cost-effective, but we find no persuasive evidence supporting TECO keeping the gasification, HRSG, and ST in reserve for a possible future conversion back to an IGCC. Because those components shall be retired, the $1,500,332 associated O&M expenses must be removed. The resulting non-fuel O&M for Polk Unit 1 is therefore $8,184,715 ($9,685,047 - $1,500,332).

2. Conclusion

TECO included $9,685,047 of non-fuel O&M expense for Polk Unit 1. Consistent with our decision on Issue 24, we remove $1,500,332 from that to reflect the retirement of the non-simple cycle components of Polk Unit 1. We therefore approve a resulting non-fuel O&M expense for Polk Unit 1 of $8,184,715.

D. Big Bend Unit 4 O&M Expense (Issue 44)

1. Analysis

Big Bend Unit 4 (BB4) is a 437 MW (summer) steam turbine that entered service in 1985. It is a dual fuel unit capable of burning coal or natural gas to produce power. TECO witness Aldazabal testified that during the test year, BB4 is scheduled for one-month outage for replacement or improvements to several systems. TECO estimated the non-fuel O&M for BB4 to be $12,472,909 in the 2025 projected test year.

Sierra Club witness Glick argued that TECO should not be allowed to operate on coal at all, and accordingly, should not recover O&M costs associated with the unit. FL Rising/LULAC adopted the position of Sierra Club. No other intervenor took a position.

We are more persuaded by the testimony and evidence presented by TECO witnesses Aldazabal and Collins. TECO witness Collins testified that while Big Bend 4 is the oldest unit in TECO's fleet, it provides reliability that is a function of investment to maintain operability. Witness Collins noted that BB4 is one of the last units TECO dispatches which allows TECO to reduce overall expenses. Additionally, TECO witness Aldazabal offered testimony that Sierra Club's economic analysis was flawed because, among other things, witness Glick compared long-term capital investments with single year operating values which resulted in inaccurate conclusions. Witness Aldazabal testified that TECO will dispatch the unit based on economic dispatch notwithstanding operational or other regulatory requirements. He further testified that BB4's dual fuel capability allows TECO to reduce its natural gas requirements and continue to serve in the event of supply shortages or reduce overall prices in the event of price shocks, and testified that BB4 is the only dual-fuel unit capable of switching quickly and for an extended period of time.

2. Conclusion

We find that BB4 is operated based on economic dispatch and that the fuel switching capability of BB4 is beneficial to ratepayers because it allows long-term access to an alternative fuel source in the event of a supply disruption or price shock. Therefore, we make no adjustments to TECO's estimated non-fuel O&M expense for BB4.

Based on the foregoing, the amount of non-fuel O&M expense associated with BB4 that we approve for the 2025 projected test year is $12,472,909.

E. Generation O&M Expense (Issue 45)

1. Analysis

TECO argued that we should approve Jurisdictional Adjusted Production (generation) O&M Expense for the 2025 test year of $125.0 million, less $285,000 per the Company's July and August Filings, for a total of $124.7 million. TECO witness Aldazabal testified that O&M expenses are incurred during planned outages, which are typically staggered on a four-to-five year interval for major units. Witness Aldazabal stated that $14.5 million of the projected 2025 test year generation O&M is associated with three outages at Bayside Unit 1, BB4, and Polk Unit 2.

Bayside Unit 1 requires a 70-day major outage to replace steam turbine rotors and other steam components. He asserted this outage is necessary, as the total run hours of the steam turbine has exceeded 380,000 hours, beyond the original equipment manufacturer's (OEM) recommended 250,000 hours. This translates into 14.8 operating-years, or approximately 21.2 calendar years at a 70 percent capacity factor, past the recommended replacement period. The Bayside Unit 1 outage contributes a projected $6 million in O&M expense.

Polk Unit 2 requires a 70-day major outage for steam turbine and generator inspections, pressure seal and rotor blade replacements, and other activities. TECO witness Aldazabal testified that this planned outage is necessary because the OEM recommends a major overhaul at 50,000 hours of operation and the unit is expected to reach 66,000 hours by the time of the outage. This translates into 1.8 operating-years, or approximately 2.6 calendar years at a 70 percent capacity factor, past the recommended outage period. Polk Unit 2 outage contributes a projected $6.0 million in O&M expense.

BB4 requires a 30-day outage for improvements to the compressed air system, seawall cathodic protection, and other activities. TECO witness Aldazabal testified this planned outage is also necessary to continue safe operation of the unit. Big Bend Unit 4 outage contributes a projected $2 million in O&M expense.

OPC witness Kollen argued that TECO's projected test year expenses are abnormally high compared to prior years by comparing the projected test year's generation maintenance of $68.5 million to actual expenses of $52.2 million in 2021, $44.8 million in 2022, $46.7 million in 2023, and budgeted expenses of $59.1 million in 2024. Witness Kollen highlighted planned generation maintenance expense specifically, projected at $25.2 million in the 2025 test year, versus the actual expenses of $8.0 million in 2019, $11.1 million in 2020, $10.3 million in 2021, $12.0 million in 2022, $9.5 million in 2023, and budgeted expenses of $13.3 million in 2024. Witness Kollen asserted that the cause of the increased expense is the number and scope of outages during the projected test year due to TECO choosing to delay maintenance and bunch the outages into 2025. The witness argued that TECO has not demonstrated that the years subsequent to the projected test year will have a similar level of generation expense so it would be inappropriate to allow TECO's requested level of generation expense as TECO would recover the abnormally high 2025-year expenses in future years until the next base rate proceeding. Witness Kollen recommended normalizing planned generation expenses and using an average of the period 2019 through 2025, using a mix of actual and budgeted values as available, resulting in a reduction of $12.4 million. He also proposed other alternatives, like capitalizing the expenses or allowing TECO to amortize the deferred expenses over an extended period of time. FIPUG and Walmart adopted the position of OPC.

In his rebuttal testimony, TECO witness Aldazabal testified that OPC witness Kollen's claim that TECO purposefully bunched outages into the projected test year is inaccurate. TECO witness Aldazabal pointed out that outages were scheduled based upon maintenance schedules and resource availability. Although during cross-examination, he conceded that TECO is ultimately in control of the maintenance schedule of its units. He also admitted during cross-examination that the forecasted budgets for 2026 and 2027 expenses are below the projected 2025 test year, but are higher than the 2023 actual values. However, he explained that exceeding the OEM's general maintenance recommendation for the Bayside Unit 1 steam turbine was attributable to good maintenance by TECO. He further testified that deferral of that particular outage was beneficial to customers because they would not pay for an unnecessary outage. With regard to Polk Unit 2 and BB4, TECO witness Aldazabal testified that these two outages were not deferred and would occur as previously scheduled.

TECO witness Chronister also testified that the Company opposes witness Kollen's normalization approach because it would not spread costs over the period but instead results in a disallowance of maintenance expense. He agreed with witness Kollen's calculation of $12.8 million for average generation outage expense, but recommends a five-year average ($14.1 million) or a three-year average ($16.0 million) should also be considered by this Commission. Witness Chronister proposed that if we opt to make an adjustment, it should allow TECO to amortize the balance over three years, or approximately $4.1 million annually for 2025 through 2027.

FL Rising/LULAC argued to include a normalized level of actual average or planned generation expenses from 2019–2025 and reduce $2.6 million for removal of the STR and Polk 1 Flexibility projects. Sierra Club argued to eliminate generation expenses associated with the use of coal or petcoke in BB4 and Polk Unit 1, and eliminate expenses entirely if they are not needed for reliability or more cost-effective than retiring. FRF argued to reduce normalized generation expenses by $12.430 million. However, no intervenor, other than OPC, filed testimony on this subject. FEA and Fuel Retailers have taken no position.

We share the concern put forward by OPC on this Issue. TECO did not demonstrate that the years subsequent to the 2025 projected test year will have a similar level of generation expense. In fact, TECO witness Aldazabal admits that forecasted expense budgets for 2026 and 2027 fall below test year values. This means that TECO would recover an abnormally high 2025-year generation O&M expense in all future years until the Company's next base rate proceeding. OPC witness Kollen provided us with a few options to remedy this. We find the normalization option to be inappropriate because, as explained by TECO witness Chronister, this method has the effect of disallowing any 2025 expense in excess of $12.8 million when we are dealing with an average (not exact) number. Rather, we find OPC witness Kollen's alternative solution to defer the atypical expense and amortize to be the better option. This will more closely align the benefits of the atypically high expense to the periods of time benefitting from the planned outages. Furthermore, this option addresses both the need for TECO to expend funds to maintain its generating fleet and also reflects that these are non-repeating expenses in future years. We further find that TECO's proposed amortization period of three years is reasonable because the 2025–2027 timeframe spans the test year and subsequent year adjustment periods. This adjustment will reduce generation O&M by approximately $8.3 million.

We note that we previously reduced O&M expenses by $1,500,332 due to the retirement of the Gasifier, HRSG, and ST at Polk Unit 1. The total resulting generation O&M for the projected 2025 test year is therefore $114,983,001 ($124,770,000 - $8,286,667 - $1,500,332).

2. Conclusion

Consistent with our decisions in Issues 24 and 43, generation O&M expense shall be reduced by $1,500,332 to reflect retirement of some of the Polk Unit 1 generating assets. For the reasons stated above we also order the amortization of the atypical expenses in 2025 over a three-year period, resulting in a reduction of $8,286,667. Therefore, generation O&M shall be $114,983,001 for the 2025 projected test year.

F. Transmission O&M Expense (Issue 46)

1. Analysis and Conclusion

TECO projects $11,491,000 million in transmission O&M during the projected test year. TECO witness Whitworth testified that this value is below the Company's O&M benchmark by $4.6 million due to efforts TECO has taken to reduce transmission O&M expenses.

No intervenor filed testimony regarding transmission O&M expense. OPC, FIPUG, FEA, Sierra Club, FRF, Fuel Retailers, and Walmart have taken no position. FL Rising/LULAC argue that that O&M should be reduced to reflect eliminating the GRR Projects. However, as discussed in Issue 19, we approved all GRR Projects. Therefore no adjustments are needed.

Based on the foregoing, we approve transmission O&M expense of $11,491,000 for the 2025 projected test year. We find that this amount is reasonable because it is supported by the evidence and because it is below the Commission's benchmark amount.

G. Distribution O&M Expense (Issue 47)

1. Analysis and Conclusion

TECO projects $54,243,000 million in distribution O&M during the projected test year. TECO witness Whitworth testified that this value is below the Company's O&M benchmark by $13.4 million due to efforts TECO has taken to reduce distribution O&M expenses.

No intervenor filed testimony regarding distribution O&M expense. OPC, FIPUG, FEA, Sierra Club, FRF, Fuel Retailers, and Walmart have taken no position. FL Rising/LULAC argue that O&M should be reduced to reflect eliminating the GRR Projects. However, as discussed in Issue 19, we approved all GRR Projects. Therefore no adjustments are needed. Based on the foregoing, we approve distribution O&M expense of $54,243,000 for the 2025 projected test year. We find that this amount is reasonable as it is supported by the evidence and it is below the Commission's benchmark amount.

H. Fuel Adjustment Clause (Issue 48)

1. Analysis and Conclusion

Fuel revenues and fuel expenses are processed through the Fuel and Purchased Power Cost Recovery Clause and associated fuel cost recovery charge. As such, fuel revenues and expenses should not be included in the derivation of base rates and must be removed. As shown on MFR Schedule C-2, page 1, TECO removed a total operating expense of $682,393,000 for "Fuel Revenues and Expenses;" however, this amount consists of both fuel- and capacity-related revenues and expenses. TECO later identified the fuel-only portion of the adjustment to be $681,258,000. The remaining capacity-only portion is addressed in our discussion of Issue 50. No contravening evidence was entered into the record regarding this amount. We find that TECO made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause.

I. Energy Conservation Cost Recovery Clause (Issue 49)

1. Analysis and Conclusion

For the 2025 test year, the estimated amount of gross revenue and expenses attributable to the Energy Conservation Cost Recovery Clause (ECCR) were estimated by multiplying forecasted clause rates by billing determinants. The test year amounts are recorded as negative adjustment entries, which indicates the amounts are reductions to total revenue and total expenses of the Company. Such reductions are appropriate because the referenced net operating revenue and expense amounts are subject to review and recovery through the ECCR mechanism, not through base rate recovery. No party in this proceeding challenged TECO's proposed conservation revenue and expense adjustments recorded in MFR Schedule C-2, Column 3. We find that TECO made the appropriate test year adjustments to its Net Operating Income to remove conservation revenues and conservation expenses recoverable through the ECCR.

J. Capacity Cost Recovery Clause (Issue 50)

1. Analysis and Conclusion

Capacity revenues and expenses are processed through the Capacity Cost Recovery Clause and associated capacity cost recovery charge. As such, capacity revenues and expenses should not be included in the derivation of base rates and must be removed. As shown on MFR

Schedule C-2, page 1, TECO removed a total operating expense of $682,393,000 for "Fuel Revenues and Expenses;" however, this amount consists of both fuel- and capacity-related revenues and expenses. In response to discovery, TECO identified the capacity-only portion of the adjustment to be $1,135,000. No contravening evidence was entered into the record regarding this amount. We find that TECO made the appropriate test year adjustments to remove capacity revenues and capacity expenses recoverable through the Capacity Cost Recovery Clause.

K. Environmental Cost Recovery Clause (Issue 51)

1. Analysis and Conclusion

TECO's MFR Schedules C-2 and C-3 demonstrate that TECO removed $9.2 million in the 2025 projected test year of NOI for the Environmental Cost Recovery Clause (ECRC). This includes $25.8 million of Operating Revenues and $16.6 of Operating Expenses for the ECRC. For 2024, TECO removed $9.8 million of NOI for the ECRC, which includes $23.8 million of Operating Revenues minus $14.0 million of Operating Revenues. For 2023, TECO removed $9.4 million of NOI, which includes $21.4 million of Operating Revenues minus $11.9 million of Operating Expenses for the ECRC. No intervenor directly disputed TECO's adjustments. We find TECO made the appropriate test year adjustments to remove $9.2 million of environmental revenues and expenses recoverable through the Environmental Cost Recovery Clause. The adjustment is reasonable and consistent with prior years.

L. Storm Protection Plan Cost Recovery Clause (Issue 52)

1. Analysis

TECO's MFR Schedules C-2 and C-3 show that TECO removed a NOI of $42.021 million in 2025 for the Storm Protection Plan Cost Recovery Clause (SPPCRC), which includes $104.364 million in total operating revenues minus $62.344 million in total operating expenses. For 2024, TECO removed an NOI of $33.042 million for the SPPCRC, which includes $86.126 million in total operating revenues minus $53.084 million in total operating expenses. For 2023, TECO removed an NOI of $23.433 million in 2023 for the SPPCRC, which includes $63.570 million in total operating revenues minus $40.137 million in total operating expenses.

2. Conclusion

Through discovery, TECO provided all SPPCRC includable costs recorded, by account, in 2023, and what TECO expects to record in 2024 and 2025. When asked why the figures did not match what was filed in MFR Schedule C-2, TECO explained that MFR Schedule C-2 contains additional components not included in its discovery response and provided explanations for these differences. No party to this proceeding challenged TECO's proposed SPPCRC revenue and expense adjustments recorded in MFR Schedules C-2 and C-3.

We find that TECO made the appropriate test year adjustments to remove all storm hardening revenues and expenses recoverable through the Storm Protection Plan Cost Recovery Clause.

M. Salaries and Benefits (Issue 53)

1. Analysis

TECO witness Cacciatore testified that this Commission should approve TECO's full salaries and benefits expense because the expenses are reasonable and necessary to have a competitive hiring process. OPC disputes TECO's request for salaries and benefit expenses. OPC witness Kollen claims that it has been Commission practice to disallow expenses that are incurred for the purpose of meeting shareholder goals, citing Order Nos. PSC-10-0131-FOF-EI and PSC-10-0153-FOF-EI. Witness Kollen then argued that allowing the Long Term Incentive Plan (LTIP) expense would be a detriment to customers, as the increase to revenue requirement would give TECO executives motivation to increase Emera's stock price as much as possible by raising rates on customers.

FIPUG and Sierra Club have adopted the position of OPC, and FRF has supported OPC in recommending a $7.170 million reduction in LTIP compensation expense. FL Rising/LULAC recommended that ratepayers should not be responsible for any TECO incentive compensation that exceeds the amount received by the top public officers of the state. FL Rising/LULAC witness Rábago addressed incentive compensation in his testimony, suggesting that TECO create a compensation plan that focuses on the customer's benefits and affordability. FL Rising/LULAC also recommended a maximum salaries and benefits amount of $359.77 million.

While we considered the testimonies and arguments presented by the intervenors, we are persuaded by the testimony in this case that TECO's request for salaries and benefit expenses in its compensation package, which includes base pay and long-term and short-term incentive plans, is necessary to attract and retain skilled team members. TECO witness Cacciatore testified that ultimately these compensation practices benefit the customer as they allow TECO to best hire and incentivize team members that will focus on safe and reliable service, which results in lowered costs for the Company and therefore customers as well.

TECO witness Cacciatore disagreed with OPC witness Kollen's method of focusing on the LTIP specifically, and instead stressed a total compensation approach. Witness Cacciatore testified that the LTIP incentivizing Emera's financial health is for the good of the Company, as Emera is TECO's source of equity. Furthermore, witness Cacciatore argued that OPC witness Kollen did not show that disallowing LTIP would not hurt the Company and customers, and claimed that removing LTIP could hurt TECO's ability to attract and retain executives responsible for customer obligations as well as force the Company to increase base pay.

TECO also offered testimony that OPC witness Kollen's reliance on Order Nos. PSC-10-0131-FOF-EI and PSC-10-0153-FOF-EI was misplaced, and that Order Nos. PSC-92-1197-FOF-

EI and PSC-02-0787-FOF-EI were more appropriate to look at for Commission precedent.[50] We agree with TECO that those two prior orders, and the evidence presented in this case, show that variable incentive plans tied to the achievement of corporate goals are appropriate. Incentive pay plans allow for companies to be competitive in hiring high quality employees, which ultimately benefits the customer.

Likewise, TECO witness Cacciatore also testified regarding Order Nos. PSC-2023-0388-FOF-GU and PSC-2023-0103-FOF-GU, both of which found the use of total compensation appropriate.[51] Order No. PSC-2023-0388-FOF-GU involved TECO's then-subsidiary, Peoples Gas System, Inc. (PGS), with a similar variable compensation design. Witness Cacciatore stated that in that case, the Commission found PGS's total salary and benefits plan to be reasonable and prudent.

We agree with TECO witness Cacciatore that the LTIP should be considered in the context of total compensation as a whole. While there are some older decisions disallowing recovery of compensation related to shareholder goals, in our more recent decisions, including the PGS cases referenced, we have found similar benefits plans to be reasonable and beneficial to customers. TECO adequately supported with testimony and evidence how the compensation package ultimately benefits customers because it allows TECO to hire and incentivize team members that will focus on safe and reliable service, translating to lower costs for ratepayers. No parties have taken issue with TECO's overall level of compensation, except for the Supplemental Executive Retirement Plan (SERP) expense, which TECO witness Cacciatore testified sits at 99.5 percent of the market median. We find that because TECO's total compensation is 99.5 percent of the market median, the Company's salary and benefits package is reasonable, as that is competitive. When reviewing overall compensation through a total compensation approach here, we do not find the LTIP objectionable. We have approved similar LTIPs in the past. Thus no adjustments reducing LTIP expense are needed.

However, the same cannot be said of the SERP expense. We are persuaded by OPC witness Kollen's testimony to disallow the SERP expense ($107,000) on the basis that it is a non-qualified expense provided only to executives, whose goals are closer to TECO's shareholders than the customers. A non-qualified pension plan is one that does not meet the IRS's Employee Retirement Income Security Act guidelines. Meanwhile, TECO witness Cacciatore argued that the SERP expense is necessary to recruit and retain talented executive leadership, which ultimately benefits the customer. Witness Cacciatore also noted that the SERP expenses contribute to executive compensation that is at the market median.

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[50] Order No. PSC-92-1197-FOF-EI, issued October 22, 1992, in Docket No. 19910890-EI, *In re: Petition for rate increase by Florida Power Corporation*; Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 20010949-EI, *In re: Petition for rate increase by Gulf Power Company.*
[51] Order No. PSC-2023-0388-FOF-GU, issued December 27, 2023, in Docket No. 20230023-GU, *In re: Petition for rate increase by Peoples Gas System Inc.;* Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-FOF-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company - Fort Meade, and Florida Public Utilities Company - Indiantown Division.*

We disagree with TECO's assertion that the SERP is intended to attract or retain employees. TECO witness Cacciatore admitted that the SERP has no actively employed participants. Furthermore, during cross examination, TECO's witness indicated that TECO has no plans to open the SERP to new employees. The SERP primarily compensates retired executives, with little benefit to the customer. Therefore SERP expense shall be removed as advocated for by OPC.

2. Conclusion

The Company's use of a total compensation approach to its benefits package is reasonable. For the reasons stated above, we approve the short term and long term compensation packages. However, the SERP primarily compensates retired executives with little benefit to customers. Therefore, we disallow recovery of expenses related to SERP. The amount of TECO's salaries and benefits that we approve for the 2025 projected test year is $376,802,000 ($376,909,000 – $107,000), accounting for removal of the $107,000 SERP expense.

N. Other Post-Retirement Employee Benefit Expense (Issue 54)

1. Analysis

This issue addresses whether TECO made the proper adjustments to pension and Other Post-Retirement Employee Benefits (OPEB) expense to reflect capitalization credits in the 2025 projected test year. OPC, FL Rising/LULAC, FRF, and FIPUG offered argument and testimony that TECO's adjustments were incorrect. Except for OPC, however, no intervenor put forward witness testimony on this Issue.

OPC witness Kollen testified that TECO did not provide a breakdown between expense and capital for total pension and total OPEB costs for the test year, despite multiple requests from OPC. There does appear to be some lack of transparency in transactions on the part of the Company, which we address that in Issue 55.

In addition, OPC witness Kollen testified that TECO has not capitalized portions of the pension and OPEB costs it is requesting recovery for. He explained that TECO recorded total pension and OPEB costs to Account 926 and then used a "fringe rate" methodology to credit the account for the capitalized portion of pension and OPEB costs. Witness Kollen asserts that this treatment is incorrect because the total pension costs and total OPEB costs do not show that they were credited for the amount being capitalized. OPC witness Kollen identified this crediting took place in historic years, but not for the 2025 test year or 2024 budgeted year. Because of this, witness Kollen recommends reducing total pension expense and an OPEB expense by $0.489 million and $0.806 million respectively to credit the portion of costs that were capitalized.

TECO witness Chronister refuted OPC witness Kollen's testimony. While witness Chronister did not disagree with Witness Kollen's description of TECO's "fringe rate" methodology to capitalize its pension and OPEB costs, the conclusions drawn by OPC are incorrect. Witness Chronister explained that this "fringe rate" methodology is the process in which the Company removes the necessary capitalized amount of pension and OPEB costs from the Company's forecasted benefits expense and that all benefit costs are initially posted to account 926, including total pension and OPEB costs. There was testimony that the credits that come from the capitalized portion of the costs are subsequently applied to account 926. Witness Chronister pointed out that MFR Schedule C-17, where pension costs are shown, reflect pension and OPEB costs before reductions are made. Witness Chronister concluded that the reductions suggested by OPC are inappropriate as the Company has already deducted the proper amounts from its benefit expense.

2. Conclusion

We are persuaded by TECO witness Chronister's explanation of how the "fringe rate" methodology works in practice. The testimony and evidence demonstrate that TECO applied it accurately. We therefore find that TECO made the proper adjustments to pension and OPEB expense to reflect capitalization credits in the 2025 projected test year. TECO made the proper adjustments to reflect capitalization credits. Therefore, no adjustments to the pension and OPEB expense is necessary.

O. Affiliated Companies (Issue 55)

1. Analysis

This issue deals with what cost allocation methodologies and what amount of allocated costs and charges, including corporate responsibility costs, should be approved for the 2025 projected test year.

TECO offered testimony that Nova Scotia Power's CAM is under the jurisdiction of the Nova Scotia Utility and Review Board, which monitors Nova Scotia Power, Inc. for compliance, which we monitor to review TECO affiliates' transactions. Because the Nova Scotia CAM Emera chooses to utilize covers transactions between Emera and its holdings, those transactions are captured whether it is called the Emera CAM or the Nova Scotia Power CAM.

Except for OPC, no party put forward witness testimony on this Issue. OPC's argued to replace the net income allocation factor with a headcount input factor persuasive or adequately supported. OPC witness Ostrander argued for a reduction of the corporate responsibility expense by $858,561. The crux of OPC's concern is about TECO's expense allocation process. OPC Witness Ostrander identified TECO's Net Income MMM allocation factor as being problematic and suggested replacing it with a Headcount input factor, using numbers from 2023. In its post-hearing brief, OPC argued that the use of a Net Income factor is "not causative, measurable, objective, stable, or predictive." The effect of witness Ostrander's recommended adjustment was that TECO's 2025 budget allocation factor fell from 72.07 percent to 67.62 percent, corresponding to a reduction of $470,606 to TECO's shared service expenses.

Witness Ostrander also suggested adjustments to TECO's Human Resource expenses that are subject to a Headcount allocation factor. Witness Ostrander claimed this was a routine adjustment to update TECO's budgeted headcount information, which resulted in Human Resource expenses being reduced by $227,646.

OPC witness Ostrander also provided testimony that due to a lack of transparency from TECO, OPC was unable to confirm the veracity of some of the transactions. Witness Ostrander specifically recommended a correction resulting in a reduction of $3,575,548 to shared service allocations for corporate responsibility, after the MMM factors have been adjusted.

OPC also expressed concern regarding TECO's procurement expenses and offered testimony that TECO's increased Procurement department expenses coupled with having less shared services with PGS resulted in TECO bearing 94 percent of all procurement expenses. Witness Ostrander suggested correcting this by replacing the "Purchase Order Spend" allocation factor with a "Net Plant Investment" factor, resulting in a $1,243,052 reduction to TECO's allocated expenses. OPC identified part of this problem as being caused by TECO's acting as the centralized service provider (CSP), which makes it hard to audit affiliate transactions as well as lead to a utility unfairly recovering costs related to procurement. According to OPC, we should remove $858,561 in Emera affiliate expenses.

TECO offered testimony that the Company's projected affiliate transactions are all for historically standard products and services shared to and from TECO's affiliates. Witness Chronister identified three ways shared services are provided to affiliates: through direct charges, assessed charges, and allocated charges. The witness also provided testimony on how the charts are allocated: when services are split between multiple affiliates, the charges are shared either through assessments or allocation. Assessed charges are those that can be assigned based on some metric of usage, such as employee headcount. When charges cannot be directly assigned to an affiliate or distributed amongst multiple affiliates through assessed then these charges are instead shared through an allocation using a Modified Massachusetts Model (MMM), which is reflected in the Company's Cost Allocation Manual (CAM).

This MMM uses total operating revenues, total operating assets, and net income as its allocation factors. Witness Chronister testified that, when applicable, the Company is in compliance with Rule 25-6.1351, F.A.C., which governs how a regulated utility allocates costs to its affiliates, as demonstrated in MFR Schedule C-30. Witness Chronister also asserted that the Company's MMM was previously found to be reasonable by this Commission. In its post-hearing brief, TECO addressed how no party has alleged that the Company has violated the Commission affiliate transactions rule. The Company further claimed that its test year affiliated transactions are below the Commission's Administrative and General functional expense group benchmark, which are reasonable and allow TECO to efficiently conduct business.

TECO witness Chronister rebutted OPC's arguments and testified that changing the Company's MMM allocation factors would be inappropriate because this would cause inconsistencies with what has been approved by the Commission in previous rate cases. Witness Chronister expressed concerns that OPC was requesting a methodology change without demonstrating such a change was prudent. Furthermore, witness Chronister argued that OPC witness Ostrander's $227,646 adjustment for headcount was inappropriate because it is based off of TECO's 2023 historical data rather than its 2025 test year data which is more accurate and reflective for the time period. For these reasons, witness Chronister testified that OPC's recommendation should not be approved.

TECO witness Chronister testified that TECO was transparent and did its due diligence in providing the required supporting documents. Witness Chronister stated that OPC witness Ostrander might have misunderstood or missed an explanation or document provided by TECO, because we have oversight of the Company's corporate responsibility, and that the Company demonstrated that it is making efforts to keep expenses down.

TECO witness Chronister testified that TECO's taking up of CSP functions has allowed the Company to run its business more efficiently by consolidating costs to avoid duplicate transactions. Witness Chronister also pointed out that this Commission monitors affiliate transactions through the Company's Diversification Pages and in Commission audits, which ensures that TECO maintains a functional structure with a reasonable cost level. Witness Chronister disagreed with OPC's nine suggestions for TECO to maintain its CSP role for three reasons. First, witness Chronister questioned if this rate case was the proper proceeding to change TECO's affiliate transactions requirements. He suggested that an amendment to Rule 25-6.1351, F.A.C., would be the more appropriate avenue to take. TECO echoed this argument in its brief when it alleged OPC took issue with affiliate transaction rules in general and not with TECO's transaction history specifically. Second, Witness Chronister noted that the charges OPC witness Ostrander takes exception with represent a small portion of TECO's overall O&M expense, which are consistently reviewed. Third, witness Chronister mentioned that of OPC's nine suggested practices, TECO already implements suggestion numbers 5, 7, 8, and 9. However, he also testified that implementing the remaining five suggestions would be unduly burdensome for TECO and result in greater costs being put onto customers.

TECO witness Chronister disagreed with OPC witness Ostrander's proposed adjustment. Witness Chronister claimed that this reduction is for an amount that TECO did not include in its budget. In fact, OPC witness Ostrander's own testimony is inconsistent on this point as he also depicts the $858,561 as not being part of the Company's 2025 budget. TECO witness Chronister asserts this correctly shows that it was not an expense TECO budgeted for, despite OPC's claim that it will impact TECO's expenses. Witness Chronister acknowledged that TECO does not record the expenses to the account OPC witness Ostrander identified, but he explained why. He said that it is because the Company budgets them to other expense accounts. Furthermore, witness Chronister stated that this charge is not due to the dissolution of TECO Services, Inc., and that the $858,561 cost was for a shared service expense budgeted for years prior to 2024. Witness Chronister also rebutted the idea that the dissolution of TECO Services, Inc. will result in increasing charges being budgeted to the Company stating that the expenses budgeted to TECO for the 2025 test year are lower than the actual amounts for 2022 and 2023.

The dispute on this Issue went further as OPC challenged TECO's use of Nova Scotia Power's CAM as Emera's CAM. OPC witness Ostrander alleged that Nova Scotia Power's CAM is not specifically named as an Emera CAM and does not address the allocation or direct assignment of services from Emera to TECO or its other U.S. affiliates. OPC alleged that TECO witness Chronister has not supplied an argument as to why there is no Emera specific CAM. Furthermore, OPC questioned if the Nova Scotia Power CAM has been approved by the FERC or this Commission. For these reasons OPC recommended that the Commission require that TECO have Emera make a CAM outlining the rules for its transactions with TECO.

2. Analysis

We do not agree with OPC that an Emera specific CAM is needed here. To do so would place form over substance. TECO witness Chronister testified that Nova Scotia Power's CAM is under the jurisdiction of the Nova Scotia Utility and Review Board, which monitors Nova Scotia Power, Inc. for compliance, and then we monitor TECO and its affiliates' transactions. Because the Nova Scotia CAM Emera chooses to utilize covers transactions between Emera and its holdings, those transactions are captured whether it is called the Emera CAM or the Nova Scotia Power CAM. Given this reality, another CAM that merely isolates Emera's charges would be redundant as explained by TECO witness Chronister. Except for OPC, no party put forward witness testimony on this Issue.

We do not find OPC's arguments to replace the net income allocation factor with a headcount input factor persuasive or adequately supported. Based on the testimony and evidence presented by TECO witness Chronister, and consistent with our precedent, we find that TECO's use of proposed allocation factors for its MMM are appropriate and that no change is needed. Additionally, we do not find OPC witness Ostrander's $858,561 proposed reduction to be appropriate. As explained by TECO witness Chronister, and even demonstrated by portions of OPC witness Ostrander's own testimony, the proposed reduction is based on the faulty notion of adjusting for a charge that was not even allocated by the Company.

We do agree with OPC witness Ostrander regarding the corporate responsibility expense. Although we do allow for prudent corporate responsibility costs, due to a lack of transparency surrounding the nature of these costs, we remove half of corporate responsibility costs, resulting in a reduction of $3,811,027. However, we do not find this rate case to be the correct setting to change TECO's affiliate transaction rules.

2. Conclusion

We therefore approve $28,650,000 in allocated costs and charges from TECO to its affiliate, and a total of $11,841,973 for allocated costs ($7,263,973) and direct charges ($4,578,000) incurred by TECO from affiliated companies for the 2025 projected test year, which reflects a reduction of $3,811,027 for the removal of half of allocated corporate responsibility costs. We also approve TECO's cost allocation methodology as discussed herein.

P. Directors & Officers Liability Insurance (Issue 56)

1. Analysis

This issue addresses Directors & Liability Insurance. TECO offered testimony that Directors and Officer (D&O) Liability Insurance and Board of Director expenses have a long Commission precedence of being approved for recovery. TECO also presented testimony that its costs are reasonable and that the expense group that these expenses are classified under is $56 million below our benchmark.

OPC took issue with TECO's request and FIPUG, FL Rising/ LULAC and FRF supported OPC in recommending an equal split of D&O Liability Insurance expense, however, no party other than OPC offered testimony on this Issue. OPC argued that some of TECO's included expenses are for its parent company, Emera, which it argued would be inappropriate because these expenses are from activities that primarily benefit Emera and TECO's shareholders, and not customers. Furthermore, witness Kollen identified instances where the Commission has previously called for an equal sharing of D&O expenses.

TECO witness Chronister provided testimony TECO witness Chronister that D&O Liability Insurance and Board of Director expenses are necessary for the Company to be able to do business, however, TECO failed to provide sufficient testimony or evidence that the shareholders are not the primary beneficiaries of these expenses.

We have considered all argument and testimony on this matter, and find that D&O Liability Insurance and Board of Director expenses are reasonable costs for doing business, and thus, OPC's adjustments should be rejected. However, while D&O Liability Insurance and Board of Director expenses are necessary for the Company to be able to do business, TECO failed to provide the charges will not primarily benefit the shareholders. It is our precedent in these instances to recommend an equal split of expenses between customers and shareholders, and we therefore find it appropriate to continue that practice here.

2. Conclusion

We therefore find there shall be an equal split of these expenses, resulting in a reduction of D&O Liability Insurance and Board of Director expenses of $527,500 for the projected test year. Specifically, $151,500 in Directors and Officers Liability Insurance and $376,000 in Board of Director expense are hereby approved, resulting in a total reduction of $527,500 for the 2025 test year.

Q. Economic Development Expense (Issue 57)

1. Analysis and Conclusion

Pursuant to Rule 25-6.0426, F.A.C., utilities are allowed to recover reasonable economic development expenses, provided that such expenses are prudently incurred. TECO witness Chronister contends that the Company has shown, for the historic and future test years, that all expenses are prudent as per Rule 25-6.0426(7), F.A.C. FL Rising/ LULAC contend that the appropriate level of economic development expense to be approved is $0; however, no witness has been proffered to testify to this position. TECO witness Chronister argued that due to no intervenor providing an argument for this Issue and as TECO has shown that their economic development expenses are prudent, that the amount of $446,502 should be approved. We agree with TECO that the Company's economic development expenses comply with the criteria of Rule 25-6.0426, F.A.C., based on the evidence in the record. We therefore find that TECO's expenses are reasonable and prudently occurred, and that the full amount of $446,502 should be approved.

R. Amortization (Issue 58)

1. Analysis and Conclusion

This Issue addresses two areas of rate case expense: the total cost and the amortization period, with the annual expense being a fall-out of those two factors. As shown on MFR Schedule C-10, TECO requested total rate case cost of approximately $2,048,000 with a three-year amortization period. This yields a test year amortization expense of $683,000. We evaluated TECO's currently requested rate case cost and found it in-line with the Company's last three rate cases filed in 2008, 2013, and 2021. The nominal estimated cost range for those cases was $1.84 million to $1.97 million. The components of TECO's currently requested rate case cost are: $1,200,000 for legal services, $748,000 for outside consultants, $100,000 for travel. The combined total of these amounts is $2,048,000. We note that FL Rising/LULAC did not submit any specific testimony in support of its suggested rate case expense of $0. We find the recovery of reasonable and prudent expense is sound ratemaking practice, and thus, find that a rate case cost of $2,048,000 amortized over a period of three years is reasonable. We hereby approve a total rate case cost of $2,048,000 with a three-year amortization period. The corresponding annual amortization expense is $683,000.

S. Operating and Maintenance Expense (Issue 59)

1. Analysis and Conclusion

This is a fall-out issue ultimately determined by other decisions contained in this Order. TECO requested Operating and Maintenance (O&M) Expense of $391.8 million for the projected 2025 test year. Based on the adjustments from Issues 11, 43, 45, 53, 55, 56, and 64, we find a reduction of $16,851,219 to O&M Expense is appropriate, and the total amount shall be $374,919,781.

T. Depreciation and Dismantlement Expense (Issue 60)

1. Analysis and Conclusion

This is a fall-out issue ultimately determined by other decisions contained in this Order. Based on the previous adjustments in Issues 7, 20, 22, 24, 43, and 64, we find there shall be a reduction of depreciation and dismantlement expense of $24,167,909 for the projected 2025 test year. This results in a depreciation and dismantlement expense of $507,268,091 for the projected 2025 test year.

U. Taxes Other Than Income Taxes (Issue 61)

1. Analysis and Conclusion

Taxes Other Than Income Taxes (TOTI) generally consists of ad valorem, gross revenue or gross receipts taxes, state unemployment insurance, franchise taxes, federal excise taxes, social security taxes, and all other taxes assessed by federal, state, county, municipal, or other local governmental authorities with the exception of income taxes.

The proposed TOTI per books is $228,359,000 (system). This amount equates to a jurisdictional TOTI of $227,796,000 (jurisdictional). Combined with the net operating income adjustments of ($126,204,000), this results in an adjusted jurisdictional TOTI amount of $101,592,000. No contravening evidence has been entered in the record regarding TECO's requested TOTI. We therefore find the Taxes Other Than Income Taxes for the 2025 projected test year should be $101,592,000 as proposed.

V. Parent Debt Adjustment (Issue 62)

1. Analysis

Rule 25-14.004(4), F.A.C., describes the parent debt adjustment calculation adjustment as multiplying the debt ratio of the parent by the debt cost of the parent, with the result multiplied by the tax rate applicable to the consolidated entity and then applied to the equity dollars of the subsidiary, excluding its retained earnings.

In this case, TECO and OPC agree that a parent debt adjustment should be made. OPC did not propose its own calculation of the PDA in this case and agreed with TECO's PDA adjustment of $12.939 million. TECO is a wholly owned subsidiary of TECO Holdings, Inc., which is a wholly owned subsidiary of Emera United States Holdings, Inc. (EUSHI), which is a wholly owned subsidiary of Emera, Inc. Tampa Electric and the other TECO Holdings companies file United States and state income tax returns on a consolidated basis with EUSHI.

TECO offered testimony supporting its PDA, and TECO witness Strickland asserted that TECO does not expect that being included in a consolidated tax return will cause any significant benefit or detriment to TECO or its customers in the 2025 test year. TECO calculated a parent debt adjustment (PDA) of $12.939 million using the capital structure of Emera Inc. consistent with the methodology used in the 2021 rate case proceeding using a common equity balance of $4,390,373,000. This adjustment decreased the Company's 2025 revenue requirement by $17.4 million.

Based on adjustments made to the capital structure and common equity balance in Issue 38, we are able to calculate the parent debt adjustment based on the adjusted common equity balance, which results in an increase to the Company's proposed parent debt adjustment. Consequently, the amount of projected test year income tax expense in Issue 70 and r revenue requirement (Issue 73) should be decreased.

2. Conclusion

Based on adjustments made to the capital structure and common equity balance in Issue 38, the jurisdictional common equity balance for TECO is $4,583,688,000. The parent debt adjustment based on the adjusted common equity balance is $13,508,663 (1.1628% × 25.345% × $4,583,688,000 = $13,508,663). This results in an increase to the Company's proposed parent debt adjustment of $569,663 ($13,508,663 – $12,939,000). Consequently, the amount of projected test year income tax expense in Issue 70 should be decreased by $569,663. This would decrease the recommended revenue requirement (Issue 73) by $765,422 ($569,663 × 1.34364 = $765,422).

The amount of Parent Debt Adjustment as contemplated by Rule 25-14.004, F.A.C., for the 2025 projected test year is $13,508,663 based on a jurisdictional common equity balance of $4,583,688,000.

W. Production Tax Credits (Issue 63)

1. Analysis

The IRA, which was signed into law on August 16, 2022, implemented substantial changes in tax law.[52] The IRA included incentives for taxpayers in the energy markets such as the extension and modification of existing ITCs and PTCs for solar projects. TECO witness Strickland testified the IRA extended the PTCs in Section 45 of the Internal Revenue Code (IRC) to electricity produced by solar energy facilities. Witness Strickland affirmed that PTCs are not calculated based on the cost of a qualifying asset, but rather, on the energy the asset produces over a 10-year period and the IRA did not impose a normalization requirement for solar PTCs.

At the time of TECO's filing, the Production Tax Credit was a tax credit that reduces income tax expense in the amount equal to $2.75 per kWh, or $27.50 per MWh, of solar energy produced by a qualifying facility during a tax year and is available for solar energy facilities that were placed in service on or after January 1, 2022. Furthermore, witness Strickland testified that under Section 45 of the IRC, the Internal Revenue Service (IRS) has authority to adjust the rate. Witness Strickland explained that the Company calculated the PTCs for the 2025 test year using

[52] H.R. 5376; Inflation Reduction Act of 2022; 26 U.S.C. § 48.

the $2.75 per kWh rate prescribed by applicable federal statutes multiplied by the estimated amount of energy to be produced by its qualified solar assets placed in service in 2022 and thereafter. Additionally, witness Strickland asserted because PTCs are allowed for a period of 10 years following the in-service date of the solar facility, the cumulative amount of PTCs expected to be claimed in the test year 2025 contributes to an income tax expense reduction of $35.4 million, which decreases the revenue requirement by $47.5 million. Finally, witness Strickland proclaimed the PTCs are the primary reason that income tax expense is lower in the 2025 test year than previous years.

During the course of the proceeding, TECO filed with the Commission on August 22, 2024, an updated revenue requirement after the issuance of the prehearing order addressing a tax law provision that occurred in July 2024, in which the IRS announced an increase to the PTC rate from $2.75 to $3.00 per kWh, or an increase from $27.50 to $30.00 per MWh generated by a qualifying asset, effective January 1, 2024. With the change in PTC rate applicable to qualifying solar assets during calendar year 2025, the $35.4 million in PTCs increased to an amount of $38.6 million in PTCs as a reduction to income tax expense for the 2025 projected test year. FL Rising/LULAC took the position that the PTCs should be flowed back to customers on a capacity basis. However, FL Rising/LULAC did not sponsor a witness that testified on this position, nor did it offer an argument in its brief. As noted in TECO's brief, FL Rising/LULAC's position on allocation of the PTCs is a cost of service/rate design issue and not a NOI issue.

FIPUG offered testimony that the Commission should adopt a consumer protection by requiring TECO to flow-through the higher of the actual PTCs earned or 100 percent of the projected PTCs associated with the proposed solar projects, and that as a prerequisite for recovering any of the solar projects investment, the future solar projects should be required to qualify for the PTCs and any portion of the investment that does not qualify should either be disallowed or not be included in rate base. FIPUG witness Ly recommended that as an alternative, customers should be held harmless and TECO should compensate customers for the value of the lost PTCs for any portion of the future solar projects that do not fully qualify. Witness Ly also testified the Commission should require that all PTCs (grossed-up for income taxes) be included as offsets to TECO's base revenue requirements associated with each future solar project that is placed into commercial operation and for which cost recovery is authorized.

TECO witness Chronister rebutted FIPUG witness Ly's recommendations and emphasized each of the solar projects included in the 2025 test year and the 2026 and 2027 SYA qualify for PTCs and the Company anticipates that solar projects included in future proceedings, beyond the ones included in this proceeding, will also qualify for PTCs. Furthermore, witness Chronister affirmed 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 PTCs (grossed-up for taxes). Witness Chronister proclaimed the Company agrees that when the Commission establishes cost recovery for solar projects included in future proceedings, beyond the ones included in this proceeding, PTCs (grossed-up for income taxes) should be offsets to base revenue requirements associated with each future solar project for which cost recovery is authorized. Witness Chronister detailed how PTCs are flow-through tax credits, and TECO has forecasted the use of flow-through accounting for solar PTCs in the 2025 test year and the 2026 and 2027 SYAs.

Witness Chronister testified that the Company will continue to use flow-through accounting for PTCs associated with solar projects.

2. Conclusion

The IRS announced an increase to the PTC rate from $2.75 to $3.00 per kWh, or an increase from $27.50 to $30.00 per MWh generated by a qualifying asset, effective January 1, 2024. With the change in PTC rate applicable to qualifying solar assets during calendar year 2025, the forecasted amount of $35.4 million in PTCs increased to an amount of $38.6 million, which equates to an increase of $3.2 million ($38.6 - $35.4 = $3.2). Therefore, the income tax expense should be further reduced by $3.2 million. The amount of Production Tax Credits that should be approved for the 2025 projected test year is $38.6 million as a reduction to income tax expense and the proper treatment is flow-through accounting.

X. Deferred Production Tax Credits (Issue 64)

1. Summary of the Issue

This Issue arises from changes to corporate income tax law as a result of the IRA and interpretation of the meaning of the term "normalization" as set forth in the 2021 Settlement Agreement. As discussed in Issue 63, the IRA implemented substantial changes in corporate income tax law which modified the tax incentives for solar projects to allow utilities to claim PTCs, which are more beneficial to the Company and customers instead of the former ITCs.

TECO offered evidence in support of its proposed use of PTCs. TECO witness Strickland testified that the Company determined the PTCs would be more beneficial to customers and, as a result, TECO elected to claim the PTCs for its solar plants placed in service in 2022 and thereafter. Beginning in 2022, TECO recorded a regulatory liability to defer the incremental tax benefits of the PTCs in place of the original estimated ITC tax amortization calculated in its 2022 base rates and 2023 and 2024 GBRA assets (Deferred PTC).

TECO witness Strickland claimed the proposed three-year amortization period recommended by OPC witness Kollen is too short because it will create an abnormal profile in the revenue requirement. The IRS allows the Company to claim a PTC for 10 years following a qualifying asset's in-service date; therefore, the Company believes it is reasonable to mirror this period for amortization of the Deferred PTCs. We note, however, that the IRS does not require the tax credit to be amortized over any period because the PTCs are expected to be claimed on the tax return in the year they are earned. During cross-examination by OPC, TECO witness Strickland agreed that for each year, TECO claims the PTCs earned for the kilowatt hours of energy produced in that tax year for all the qualified solar facilities in-service.

The as-filed Deferred PTC benefit on a revenue equivalent basis as of December 31, 2024, was expected to be $55.3 million. In addition to recording a regulatory liability to defer the incremental tax benefits, TECO proposed to amortize the regulatory liability as a reduction to income tax expense over a period of 10 years beginning January 1, 2025. Witness Strickland testified that the proposal would reduce the as-filed 2025 test year revenue requirement by approximately $5.5 million and is consistent with the 10-year period for which PTCs are available for a project under the IRC. The $5.5 million reduction was reflected on line 7 of MFR Schedule C-4, page 4 of 8.

As also discussed in Issue 63, TECO filed with the Commission on August 22, 2024, an updated revenue requirement that addressed the change in PTC rate announced by the IRS in July 2024, increasing the rate from $2.75 to $3.00 per kWh generated by a qualifying asset, effective January 1, 2024. Given the Company's updated revenue requirement, the Deferred PTC benefit from calendar years 2022 through 2024 increased to $58,743,299 (revenue equivalent basis), which reflects $3,516,213 of additional PTC benefit from the original filing due to the change in PTC rate applicable to qualifying assets for calendar year 2024. With the change in PTC rate applicable to calendar year 2024, and using the Company's proposed 10-year amortization period, the $5.5 million reduction to the as-filed 2025 test year revenue requirement increased to approximately $5.85 million.

OPC witness Kollen recommended the treatment of the Deferred PTC regulatory liability, including a deferred return (carrying costs) on the regulatory liability for the years 2022 through 2024, be refunded over a three-year amortization period. Witness Kollen asserted the Company offered no rationale for the 10-year amortization period other than the fact that PTCs are available for new solar resources annually for 10 years. Furthermore, witness Kollen emphasized there is no true nexus between the number of years the PTCs are available for new solar generating assets going forward (test year and subsequent years) and the refunds related to the deferral period preceding the test year.

In addition, OPC witness Kollen elaborated on how a 10-year amortization period is unjustifiably long as customers were entitled to the PTCs as they were earned through reductions to the base revenue requirement and reductions to the 2023 and 2024 GBRAs pursuant to the 2021 Settlement in the prior rate case. Witness Kollen testified the refunds to the customers should be made sooner rather than later, especially since the Company failed to record deferred carrying costs on the deferred PTCs and failed to include the PTCs as cost-free capital in the capital structure. Witness Kollen expanded on how a three-year amortization period is more reasonable, and given TECO's recent filing history, he opines that three years is the likely number until the Company's next base rate case proceeding.

OPC witness Kollen testified that the Company should have added a deferred return (carrying costs) to the Deferred PTCs on a revenue equivalent basis to ensure that customers received the same economic value as if the PTCs had been flowed-through as reductions to the 2023 and 2024 GBRA rate increases as if the PTCs were earned each year. Witness Kollen recommended the Commission compensate customers for carrying costs on the Deferred PTCs by adding the carrying costs calculated at the allowed return from the prior rate case to the regulatory liability. Witness Kollen calculated the effects of the recommended carrying costs to be a reduction of at least $0.887 million in the claimed revenue requirement and requested base revenue increase, consisting of an increase of $0.460 million in the negative amortization expense and a decrease of $0.427 million due to the additional regulatory liability in the test year times the grossed-up rate of return (equity only).

Witness Kollen further testified that the effects of his recommended treatment, including the three-year amortization period and carrying costs, are a reduction of at least $13.182 million in the claimed revenue requirement and requested base revenue increase, consisting of a $13.845 million increase in the negative amortization expense, offset in part by $0.663 million for the increase in the test year rate base due to shorter amortization period multiplied by the grossed-up cost of capital.

During rebuttal, TECO witness Strickland claimed the proposed three-year amortization period recommended by OPC witness Kollen is too short because it will create an abnormal profile in the revenue requirement. The IRS allows the Company to claim a PTC for 10 years following a qualifying asset's in-service date; therefore, the Company believes it is reasonable to mirror this period for amortization of the Deferred PTCs. We note, however, that the IRS does not require the tax credit to be amortized over any period because the PTCs are expected to be claimed on the tax return in the year they are earned. During cross-examination by OPC, TECO witness Strickland agreed that for each year, TECO claims the PTCs earned for the kilowatt hours of energy produced in that tax year for all the qualified solar facilities in-service.

During cross examination, TECO witness Chronister agreed that the IRS "established PTC credits as a flow-through credit." Witness Chronister suggested that 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. Furthermore, witness Chronister continued with what would seem to be a compromise, emphasizing if the Commission did in fact approve a five-year amortization period for the regulatory liability (Deferred PTC Benefit), the 2025 NOI adjustment would be $5.520 million.

In its brief, OPC argued that Section 11(c)(iv) of the 2021 Settlement Agreement states that "[t]he company will adjust any GBRA that has not gone in effect up or down to reflect the new corporate income tax rate and the normalization of any new tax credits applicable to Future Solar Projects on the revenue requirement for the GBRA." Instead, TECO deferred the excess amount from the election of PTCs from 2022 through 2024 and created a regulatory liability for this difference rather than adjust the 2023 and 2024 GBRAs. OPC argued that the regulatory liability represents a benefit that the customers are entitled to in the year earned and should have received as a reduction to the GBRA rate increase.

2. Analysis

The record before us demonstrates that there was some ambiguity regarding the meaning of normalization and how it pertains to this Issue given the timing of the 2021 Settlement Agreement and the enactment of the IRA. Furthermore, we are cognizant that PTCs are available for solar energy facilities placed in-service on or after January 1, 2022, and may be claimed annually for ten years following the in-service date of the solar facility. Under TECO's proposal, the solar facilities placed in-service during calendar years 2022 through 2024 would earn PTCs for ten years but the amortization period would not begin until 2025, therefore extending the actual recovery period for the customers beyond the 10-year amortization period even though the

IRS established PTCs as a flow-through tax credit in the year it was earned. We cannot find that doing so would be in the interest of ratepayers.

Additionally, the customers would not see the same value of the Deferred PTC benefit as the Company for those assets placed in-service during calendar years 2022 through 2024 if the Commission approved the 10-year period proposed by TECO due to the amortization period being extended beyond the 10-year eligibility period. OPC addressed this aspect in its brief, adding that the IRA legislation giving rise to the PTCs made the benefit of the PTCs available annually for only a 10-year period. OPC correctly recognized that using the Company's proposed amortization period of 10 years (starting in 2025 for PTCs earned from 2022 through 2024) would flow through the Deferred PTC benefits to customers outside the 10-year period.

Having heard to the testimony, reviewed the evidence, and had the benefit of argument from the parties, we find OPC's argument to be the more persuasive one. The record is clear that the intent of the term "normalization" in Section 11 of the 2021 Settlement Agreement contemplated the normalization for ITCs as required by Section 45 of the IRC before the enactment of the IRA. Therefore, the tax law change provision in the 2021 Settlement Agreement should not take precedence over the requirements and provisions of the new tax law for which Section 11 in the 2021 Settlement Agreement was intended to implement. We also find that a three-year amortization period, as testified to by OPC witness Kollen, is more reasonable given the nature of the PTCs being established as a flow-through credit and the customers should receive the same benefit or economic value of the PTCs as the Company.

Furthermore, the evidence in the record makes a three-year amortization period appear the more rational option. It facilitates customers being made whole sooner. Given TECO's recent filing history, three years is also the likely number of years until the Company's next base rate case proceeding. Based on what was presented, we conclude that the appropriate treatment for the Deferred PTCs is to return the benefit to customers as soon as possible unless TECO demonstrated that its cash flow would be impacted to the extent it would harm its financial integrity and credit ratings. TECO has not demonstrated that a three-year amortization period would be detrimental to its financial integrity or credit ratings, which in part, is inferred by TECO witness Chronister's rebuttal to OPC's recommended three-year amortization period with the Company's counterproposal of a five-year amortization period. Finally, we note the fact FIPUG, FL Rising/LULAC, FRF, Sierra Club, and Walmart were in agreement with OPC's position regarding both the three-year amortization period and the addition of carrying costs to the Deferred PTC regulatory liability.

Witness Strickland testified that OPC witness Kollen's proposed NOI adjustment of $12.993 million, excluding carrying charges is correct. However, witness Kollen's estimated revenue impact did not consider the recent increase in the PTC rate from $2.75 to $3.00 per kWh for 2024 and thereafter. Therefore, we find using witness Kollen's methodology to calculate the deferred PTC benefit for an amortization period of three years is reasonable and supported by the evidence. Based on TECO's revised Deferred PTC benefit filed in its August 22, 2024 letter, we calculated the necessary adjustment to reflect a three-year amortization period, including a carrying charge, for the treatment of the Deferred PTC benefit. The PTC benefit that was deferred in 2022–2024 in the amount of $58.74 million shall be accounted for as a regulatory liability, amortized over a three-year period for annual amortization in the amount of $19.58 million ($58.74 million ÷ 3 years), with an additional $1.56 million carrying charge, resulting in an annual amount of $21.14 million.

In its original filing and MFRs, the Company included a PTC benefit of approximately $5.50 million for the 2025 projected test year ($55.3 million ÷ 10 years). Therefore, we find that TECO's requested revenue requirement shall be reduced by $15.64 million ($21.14 million – $5.50 million = $15.64 million). This also results in a decrease of $11.64 million to the annual Amortization Expense. A corresponding adjustment to decrease rate base by $219,567 shall also be made. The rate base should be decreased by the difference between TECO's revenue requirement reduction in its original filing ($55.227 million) and our approved revenue requirement reduction ($63.223 million), which equates to $7.996 million ($7.968 jurisdictional). The rate base reduction should be offset by the 13-month average of the Amortization Expense ($15.497 million), which is $7.749 million. The net rate base adjustment is a decrease of $219,567 ($7.968 million - $7.749 million = $219,567).

3. Conclusion

In sum, the PTC benefit that was deferred in 2022–2024 in the amount of $58.74 million shall be accounted for as a regulatory liability, amortized over a three-year period for annual amortization in the amount of $19.58 million, with an additional $1.56 million carrying charge, resulting in an annual amount of $21.14 million. Therefore, we reduce TECO's requested revenue requirement by $15.64 million. A corresponding adjustment to decrease rate base by $219,567 shall also be made.

Y. Investment Tax Credits (Issue 65)

1. Summary of the Issue

This Issue addresses the impact of ITCs for ratemaking purpose as a result of the IRA, which became effective on August 16, 2022. The IRA made a 30 percent ITC available for energy storage facilities placed in service beginning in 2023. In general, ITCs are calculated as a fixed percentage or rate times the total cost of the qualifying asset and are reflected on the tax return for the year in which the asset goes in service. Prior to the IRA, for ratemaking purposes, the IRC and IRS Treasury Regulations require that the total amount of the ITC be amortized over the life of the asset as a reduction to income tax expense (i.e., be "normalized"). This created a smoothing effect that minimizes large, ITC-based changes to tax expense by recognizing the value of the credit for ratemaking purposes ratably, not all at once when an asset goes in service.

Normalization accounting has the effect of leveling customers' rates over time, and therefore avoiding volatility in the company tax expense profile, which would occur should the company elect out of normalization. The IRA introduced a provision that allows a taxpayer to elect out of the IRS normalization rules for energy storage facilities and amortize the ITC at a faster rate than the depreciation rate or regulatory life of the asset.

On July 24, 2024, TECO submitted an adjustment letter that revised the in-service dates for Lake Mabel Energy Storage and South Tampa Energy Storage. In regard to Lake Mabel, the Company updated the in-service date from April 2025 to January 2025 and for South Tampa from April 2025 to December 2025. The effect of these updates would be an increase in the 2025 revenue requirement by $2.1 million dollars and a decrease in the SYA 2026 and 2027 by $2.4 million dollars and $0.4 million dollars, respectively. On August 22, 2024, TECO filed an updated revenue requirement document which changed the proposed service life as originally filed for energy storage assets of 10-years to 20-years. According to the filed document, the changes decreased the Company's proposed 2025 revenue requirement by $2,623,117 and decreases its proposed 2026 and 2027 SYA by $1,352,721 and $91,305, respectively.

2. Analysis

In this case, we must determine if TECO should take advantage of the IRS's revised normalization rules and opt-out of the normalization requirements for energy storage assets and determine if TECO three-year amortization period is beneficial to customers without causing financial harm to TECO. OPC took issue with TECO's normalization methodology.

FL Rising/LULAC did not offer an argument but took the position, also adopted by Sierra Club, that the ITCs should be treated as if TECO opted out of the normalization requirements and the ITCs should be deferred and amortized over 10 years. FEA and Fuel Retailers took no position.

OPC witness Kollen recommended we reflect the ITCs as if the Company elected and will continue to elect out of the IRS normalization requirements. It is an annual election and the Company has not yet filed its 2023 federal income tax return or its 2024, 2025, 2026, or 2027 federal income tax returns. Witness Kollen also recommended we direct the Company to defer the ITCs pursuant to the IRA earned each year, and to amortize the deferred ITCs over a three-year amortization period, the same period that he recommended for the deferred PTCs earned in the years 2022 through 2024 and for the same reasons. Witness Kollen's recommendation would produce a reduction of $3.493 million in revenue requirement. Witness Kollen also recommended that the new ITCs be recorded as cost-free capital in the capital structure instead of including them at the weighted average cost of capital. OPC's position and argument was also adopted by Walmart and FIPUG, with FRF taking a substantially similar position as well.

TECO methodology for normalization of the ITCs for energy storage devices is consistent with the our long-standing practice of normalizing ITCs. TECO provided persuasive evidence it will avoid intergenerational cost inequities, which would allow customers who will pay for the asset to enjoy the benefit of the tax credits over the life of the asset. TECO offered support for its normalization methodology with testimony that the general normalization rules have been in place since 1986 and is a method of accounting in which tax benefits associated with accelerated depreciation and ITC from regulated companies are spread over the same time period that the costs of investments are recovered from customers. The objective of normalization is to ensure that current and future customers are treated equitably by allowing all customers to enjoy the tax benefits associated with the utility assets. However, for ratemaking purposes, TECO calculated the ITC in accordance with the IRS normalization rules and deferred and amortized the ITC over the regulatory live of the asset, which at time of filing was 10 years, later revised to 20 years. TECO will claim the new 30 percent ITC in the amount of $42.3 million for its qualified standalone energy storage facilities expected to be placed in service in 2025. This would reduce the 2025 projected test year income tax expense by $1.4 million.

Based on a review of the parties' testimony and arguments, we find TECO should take advantage of the IRS's revised normalization rules and opt-out of the normalization requirements for energy storage assets. However, we agree with TECO that a three-year amortization period is too short, and find a five-year amortization period is beneficial to customers without causing financial harm to TECO.

OPC witness Kollen recommended the Commission reflect the ITCs as if the Company elected and will continue to elect out of the IRS normalization requirements. It is an annual election and the Company has not yet filed its 2023 federal income tax return or its 2024, 2025, 2026, or 2027 federal income tax returns. Witness Kollen also recommended we direct the Company to defer the ITCs pursuant to the IRA earned each year, and to amortize the deferred ITCs over a three-year amortization period, the same period that he recommended for the deferred PTCs earned in the years 2022 through 2024 and for the same reasons. Witness Kollen's recommendation would produce a reduction of $3.493 million in revenue requirement.

We are persuaded by the testimony that the three-year amortization period for battery storage proposed by OPC is too short, would create intergenerational inequities (benefits will accrue only in early years of an asset's life) and an abnormal ratemaking earnings profile, and should be rejected in favor of a longer period of 10 years or more. Further, TECO witnesses Chronister and Strickland disagreed with OPC's proposal to reflect the deferred ITCs as zero-cost capital in the capital structure. The Company's methodology complies with IRS normalization rules and is consistent with the Company's historical treatment of its deferred ITCs. The Company's treatment is consistent with FPSC practice, which is to assign a cost of capital for the deferred ITCs using the weighted average cost rate of investor sources of capital. This practice has been codified in Commission orders for the last several decades. We agree with TECO and the deferred ITCs shall be assigned the average cost rate for the investor sources of capital (7.64 percent) which is discussed in Issue 34.

3. Conclusion

Based on a review of the parties' testimony and arguments, we find TECO should take advantage of the IRS's revised normalization rules and opt-out of the normalization requirements for energy storage assets. However, we agree with TECO that a three-year amortization period is too short, and find a five-year amortization period is beneficial to customers without causing financial harm to TECO.

We adjusted the battery storage ITC annual amortization amount to reflect an amortization period of five years based on TECO witness Strickland's ITC calculations in her revised rebuttal testimony filed on July 31, 2024. Our calculation is summarized in Table 14.

Table 14
Calculation of 5-year Amortization for 2025

Project	Cost	ITCs	Annual Amortization	In service proration	2025 Amortization
Wimauma	$50,709,000	$15,212,000	$3,042,540	0.8333333	$2,535,450
Lake Mabel	$54,457,495	$16,337,249	$3,267,450	0.9166667	$2,995,162
Dover	$18,270,000	$5,481,000	$1,096,200	1.0	$1,096,200
Total					$6,626,812

TECO's original filing included an estimated annual amortization expense amount of $3.743 million. After the change of in-service dates for some of the battery storage assets, we calculated amortization expense in the amount of $6.627 million (including the Dover battery storage asset), which equates to an increase of $2.883 million. ($6.627 million - $3.743 million) After applying the NOI multiplier of 1.34364, the approved revenue requirement reduction is $3.874 million for the 2025 projected test year.

Ultimately, we hereby approve a five-year amortization period for Investment Tax Credits for Battery Storage assets as if the Company opted out of normalization. The amount of the Investment Tax Credits related to the battery storage assets is $37.031 million and the annual amortization should be $6.627 million for the 2025 projected test year.

Z. Income Tax Expense (Issue 66)

1. Analysis and Conclusion

This is a fall-out issue. TECO requested an Income Tax expense of ($8.3 million) for the projected 2025 test year. Based on adjustments to Issues 64, 65, and 70, along with corresponding adjustments to all NOI issues, we find an increase in Income Tax expense of $7,227,835. Therefore, we approve an Income Tax expense amount of ($1,099,165) for the projected 2025 test year.

AA. Net Operating Income (Issue 67)

1. Analysis and Conclusion

This is a fall-out issue. Based on the previous adjustments in Issues 7, 11, 20, 22, 24, 41, 43, 45, 53, 55, 56, 64, 65, and 70, we approve a Net Operating Income of $546,971,153 for the projected test year.

VIII. 2025 Revenue Requirement

This section addresses the 2025 revenue requirement and includes items identified as Issues 68 and 69 in the Prehearing Order. Specifically, this section addresses the Revenue Expansion Factor (Issue 68) and the Annual Operating Revenue Increase (Issue 69), a fall-out of the determinations made for Plant in Service, ROE, and Net Operating Income.

A. Revenue Expansion Factor (Issue 68)

1. Analysis

On MFR Schedule C-44, TECO calculated a net operating income multiplier of 1.34364. This multiplier is based on a revenue expansion factor of 74.424 percent, formulated using a 0.0848 percent factor for regulatory assessment fees, a 0.224 percent bad debt rate, a 5.5 percent state income tax, and a 21.0 percent federal Income Tax rate. No other party to this proceeding took an alternative position to TECO's requested net operating income multiplier. The net operating income multiplier calculation is shown in Table 15.

FL Rising/LULAC took the position that "the revenue expansion factor and net operating income multiplier should be adjusted to reflect a 50-50 equity-to-debt ratio." We note the net operating income multiplier will be applied to any net operating income differential we determine appropriate. Therefore, the net operating income multiplier is "downstream" of the equity ratio determination as addressed in Issue 38.

Table 15
NOI Multiplier

Description	Value
Revenue Requirement	100.000%
Less Regulatory Assessment Fee	0.0848%
Less Staff Calc. Bad Debt Rate	0.224%
Net Before Income Taxes	99.691%
Less State Income Tax @ 5.5%	5.483%
Net Before Federal Income Tax	94.208%
Less Federal Income Tax @ 21.0%	19.784%
Revenue Expansion Factor	74.424%
NOI Multiplier (100/74.424)	1.34364

2. Conclusion

We find that the appropriate revenue expansion factor should be 74.424 percent and net operating income multiplier should be 1.34364 for the 2025 projected test year, including the elements and rates discussed in the analysis portion of this recommendation.

B. Annual Operating Revenue Increase (Issue 69)

1. Analysis and Conclusion

This is a fall-out issue dependent on our determinations on other issues. In its original filing, TECO requested a total operating revenue increase of $297,802,000 for the projected 2025 test year. Based on the previous adjustments to Plant in Service (Issue 25), ROE (Issue 39), and Net Operating Income (Issue 67), we find an operating revenue increase of $184,762,364 for the projected test year 2025.

IX. 2025 Cost of Service and Rates

In this Section we determine the appropriate cost of service for TECO, deciding the issues identified in the Prehearing Order as Issues 70–93. The main disagreement between the parties revolves around the selection of the appropriate methodology for allocating the various costs it incurs amongst the rate classes it services, including Production Costs (Issue 71), Transmission Costs (Issue 72), and Distribution Costs (Issue 73).

Rule 25-6.043(1)(a), F.A.C., establishes MFRs for electric IOUs petitioning for a rate increase. The rule requires submission of a cost of service study using the 12 Coincident Peak and one-thirteenth Average Demand (12 CP and 1/13 AD) cost allocation methodology. TECO complied with this MFR. However, TECO also filed a separate cost of service study using 4 Coincident Peak (4 CP) and full Minimum Distribution System (MDS) for our consideration. While our rule establishes minimum criteria regarding cost of service studies, it does not foreclose our consideration of alternative proposals if the MFRs were also satisfied.

Three parties (TECO, FIPUG, and FEA) submitted testimony in support of 4 CP with MDS. The 2021 Settlement Agreement provided that TECO will, in its next rate case proceeding, file a cost of service MFRs using the 4 CP and full MDS methodologies for cost allocation and that all signatories will either support, or not oppose, the full 4 CP with MDS implementation. FL Rising/LULAC were not a party to TECO's 2021 rate case and filed testimony objecting to the use of the MDS methodology and supported a 12 CP methodology with either 1/2 AD or 1/13 AD.

A. Wholesale and Retail Allocation (Issue 70)

1. Analysis

TECO proposed a separation of the various costs it incurs into wholesale and retail customer components. TECO provided an explanation of the methodology used to develop separation factors for each cost component in MFR Schedule E, Volume I.

In its brief, FIPUG supported TECO’s jurisdictional separation cost of service study. No other party took a position on this issue. TECO witness Williams explained the need for the jurisdictional separation study in his direct testimony, stating that it allowed TECO to allocate costs to wholesale and retail customers in a manner consistent with TECO's previous filings. Witness Williams stated that TECO does not currently provide long-term firm requirements electric power service to any wholesale customers. TECO provides transmission service to two Open Access Transmission Tariff customers, Seminole Electric Cooperative, Inc. and DEF. Retail business represents 100 percent of production and distribution plant and 93.52 percent of transmission plant.

2. Conclusion

TECO's proposed separation of costs and revenues between the wholesale and retail jurisdiction is appropriate and should be approved as shown in MFR Schedule E, Volume I.

B. Production Costs (Issue 71)

1. Analysis

In this issue we determine the appropriate methodology to allocate production costs to the various rate classes served by TECO. As the name implies, "Coincident Peak" (CP) demand reflects the contribution to the system monthly peak demand for each of the rate classes. At the hour of the system peak in a given month, the CP demand for any given class would be that class' proportion of that hour's system peak demand. There can also be an Average Demand (AD) component that relates to energy usage.

TECO proposed a cost of service study allocating production demand costs using the 4 CP cost allocation methodology. However, TECO also submitted a cost of service study using the 12 CP and 1/13 AD cost allocation methodology because it is required by our rule to do so. Our rule does not foreclose the consideration of TECO's proposed 4 CP alternative. Support for cost allocation using either methodology can thus be found in the record before us.

The 4 CP methodology focuses on the peak demand in a selection of 4 months (in this case, January, June, July, and August) of the year, while the 12 CP methodology looks at the peak demand in each of the 12 months. Including a 1/13 AD component with the 12 CP method recognizes there is an energy component associated with production plants. Stated in percentages, the 12 CP and 1/13 AD methodology allocates approximately 92 percent of production plant based on each rate class' demand that is projected to occur coincident with each of the 12 monthly system peaks and approximately 8 percent on each rate class' share of average demand.[53]

FL Rising/LULAC primarily advocated for the 12 CP and 50 percent AD methodology. However, in the alternative, they also advocated that we direct TECO to use the 12 CP and 1/13 AD method. They argued that TECO's use of the 4 CP production demand allocator unjustly increases the share of production-related retail costs that residential customers must bear relative to other rate classes when compared to the 12 CP alternatives. FL Rising/LULAC witness

[53] Average Demand is mathematically the same as allocating costs on an annual energy usage basis. It is the total energy usage divided by the number of hours of use.

Rábago testified that, along with the use of the Minimum Distribution System (MDS), the use of the 4 CP allocation method increases costs to residential customers. Whereas if the highest peak days on each of the 12 months are sampled, larger customers will be assigned more costs based on their consistently high usage across the year.

TECO's proposed 4 CP method allocates costs to the rate classes based on the rate classes' projected average contribution to the system peak during the test year period months of January, June, July, and August, which were selected in the 2021 Agreement. TECO witness Williams explained that the use of these particular four months was reasonable because they are the months in which peak demand was projected to be above 4,000 MW in TECO's most recent Ten-Year Site Plan. The Ten-Year Site Plan focuses on two system peaks for calculating reserve margin: a summer peak and a winter peak. TECO maintains that this consideration alone could arguably support a 2 CP methodology. There is thus evidence in the record that the 4 CP approach is a middle ground between the historical 12 CP and the 2 CP summer and winter peak focus implicit in the Ten-Year Site Plan. Cost allocation is a matter of judgment upon which reasonable people may disagree.

We are more persuaded by the testimony and evidence offered in support of the 4 CP methodology. We find that the selection of which CP months to use in this case was reasonable for the reasons stated above. Because TECO's peaks are primarily a function of energy consumption associated with weather, we find that there is a strong correlation between weather and residential and small commercial energy consumption. Large commercial and industrial customers tend to be high load factor customers and their consumption is not as strongly correlated to weather; therefore their energy consumption stays fairly consistent throughout the year. The 4 CP method more closely allocates costs to those customer classes of TECO that are responsible for driving up system peak demand. Giving equal weight to non-peak months via the 12 CP method would dilute the impact of demands occurring in peak months and therefore shift costs away from the cost-causers. We also find that TECO's transition from large coal-fired generation units to cleaner resources, like solar, has diminished the importance of shoulder months for operational planning and cost attribution purposes. Our decision is further supported by the testimony from TECO witness Williams stating an additional benefit of the 4 CP method is that it can serve as a catalyst for economic development by making manufacturers and other large employers in TECO's service territory more competitive than competing regions.

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

The witnesses supporting the 4 CP methodology did not limit themselves to general arguments but also explained why this methodology is more appropriate for TECO specifically. For example, FIPUG witness Pollock testified that TECO's own system planning principles align more closely with 4 CP than 12 CP. Furthermore, the National Association of Regulatory Utility

Commissioners' cost allocation manual states that the "12 CP method is usually used when the monthly peaks lie with a narrow range, i.e., when the annual load shape is not spiky." In other words, 12 CP is usually used when the demand variability between months results in gentle curves, not when interspersed with sharp spikes. FIPUG witness Pollock produced a graph that demonstrates TECO's annual load shape is in fact spiky.

Additionally, FIPUG witness Pollock presented a chart to highlight the differences in TECO's monthly system peak demands, with the summer months of June, July, August, and September showing the highest peaks based on the historical period of 2020 through 2025. While January is not peak month in that chart, witness Pollock asserted that TECO is currently projecting a winter peak in January 2025 and is also projecting more peak load growth during the winter months than the summer months. Witness Pollock warned that under a 12 CP method for TECO "the lights would go out" because if TECO only plans for capacity to meet the average of the 12 CPs during the test year, that 4,012 MW (plus reserves) would not be sufficient to meet the 4,566 MW peak demand projected for January or the 4,366–4,421 MW peaks projected for June, July, and August. We find the testimony and evidence presented by TECO, FIPUG, and FEA persuasive that, at this time and for this utility, 4 CP is the better cost allocation methodology to apply in order to meet TECO's customer needs, except as stated below regarding Big Bend Unit 4 (BB4).

More specifically, despite our overall decision regarding 4 CP in this case, TECO's BB4 scrubber shall continue to be allocated on an energy basis consistent with our prior orders.[54] FIPUG witness Pollock testified that there was no valid reason to classify this investment differently (i.e., energy-related) than the remaining investments in the plant, but we rejected that argument previously in Order No. PSC-09-0283-FOF-EI and we do so again now.[55] FIPUG witness Pollock has not presented any new or persuasive rationale to warrant changing the cost allocation we determined was appropriate for this specific asset. We thus agree with TECO that the BB4 scrubber should continue to be allocated on an energy basis.

2. Conclusion

Based on the evidence presented, the appropriate cost allocation methodology for TECO is the 4 CP methodology. However, the BB4 scrubber shall continue to be allocated on an energy basis. TECO filed a revised cost of service study, including rates and tariffs, that reflected our vote on all issues. Our approved methodology shall also be utilized for TECO in other cost recovery clauses for allocation of production demand classified costs to the rate classes.

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[54] As discussed in Issue 24, we find that the Polk Unit 1 gasifier should be retired, therefore, the allocation for this asset is moot. Nonetheless, we would be remiss to not point out that TECO witness Williams testified that we have deemed the gasifier to be fuel related, thus energy related, since at least TECO's last four rate cases. Were the gasifier still active, FIPUG fails to convince us to change that prior allocation method today.

[55] Order No. PSC-09-0283-FOF-EI, issued Apr. 30, 2009, Docket No. 20080317-EI, *In re: Petition for rate increase by Tampa Electric Company*.

C. Transmission Costs (Issue 72)

1. Analysis and Conclusion

Transmission costs should be allocated consistent with our decision on the previous issue, Issue 71, regarding the allocation of production costs. We approved TECO's proposed 4 CP methodology, therefore TECO's transmission costs shall also be allocated based on the 4 CP methodology.

D. Distribution Costs (Issue 73)

1. Summary of the Issue

Five witnesses testified in this proceeding regarding the appropriate methodology to allocate distribution costs to the rate classes. The selection of the appropriate distribution cost allocation methodology affects how much of the revenue requirement should be allocated to each rate class which has a direct impact on the rates customers pay.

The standard classification of electric utility costs are demand-, customer-, and energy-related costs. Distribution costs are composed of both demand- and customer-related costs. Only distribution plant in accounts 369 (service drops) and 370 (meters) are classified as customer-related and distribution costs in accounts 364 through 368 (poles, overhead lines, underground lines, and transformers) are classified as demand-related. This classification method classifies only the line from the transformer to the meter (service drop) and the meter itself as customer-related and, therefore, must be allocated on the basis of number of customers. All other distribution facilities are allocated on a demand allocator on the theory that load determines the size of facilities. The customer allocator is calculated by dividing the number of customers in each rate class by total customers. Customer and demand allocators vary by rate class, resulting in assigning more or less costs to a rate class depending on the allocator used.

MDS is an alternative methodology for classifying distribution plant. It rests on the premise that the number of poles, lines (conductors), and transformers varies with the number of customers on the system. Specifically, the MDS method classifies a greater proportion of the costs in accounts 364 through 368 as customer-related, with the remaining portion as demand-related.

TECO witness Williams explained that the MDS methodology classifies a portion of the primary and secondary voltage distribution system as customer-related costs. To arrive at this allocation between a demand and customer classification, TECO applied a zero-intercept analysis to determine how much of each account is to be allocated on demand and how much on customers. The zero-intercept methodology involves creating a graph of the unit costs of distribution equipment of varying sizes and estimating a regression line that passes through the zero intercept, or vertical axis, at some positive value. The value of the zero intercept is the statistical estimate of the customer component of the cost of a single unit of the equipment that has, theoretically, zero capacity.

2. Analysis

TECO's primary argument in support of MDS was that the 2021 Settlement Agreement requires it to implement a full MDS cost classification methodology. Besides the language in the 2021 Settlement Agreement, TECO put forth some additional reasons why the MDS methodology should be approved in this case, including that: (1) MDS is a methodology used in the utility industry; (2) the principles underlying MDS are consistent with the National Association of Regulatory Utility Commissioners' (NARUC) cost allocation manual, (3) MDS represents the utility's readiness to serve customers; and (4) fully implementing MDS aligns with cost-causation principles. FIPUG and FEA echoed these arguments.

a. MDS Acceptance in Florida

Although we have previously approved the MDS methodology for investor-owned electric utilities as a provision in settlement agreements,[56] we have typically rejected this methodology in litigated rate cases. For example, by Order No. PSC-02-0787-FOF-EI (2002 Gulf order), we denied the MDS methodology in the 2002 Gulf Power Company rate case.[57] The 2002 Gulf order refers to numerous orders from the 1980s in which we have consistently rejected the use of the MDS methodology.

In order to separate the total costs of poles, transformers, and overhead and underground lines into two cost components, TECO conducted a MDS study using the zero-intercept method. As witness Williams explains, "The zero-intercept method is a linear regression analysis that relates a distribution item's unit costs (dependent variable) to its associated capacity values (independent variable)." Based on a linear regression of the cost data, TECO determined the hypothetical unit cost of distribution facilities with no voltage capacity, which defined the per unit customer-related cost. The per unit customer-related cost was then multiplied by the total number of that equipment, with the resulting amount classified as customer-related costs and the remaining costs associated with the equipment classified as demand-related. The resulting customer- and demand-related costs are expressed as percentages and applied to the appropriate embedded plant account. Separate regression analyses were conducted for each of the FERC accounts associated with overhead transformers, underground transformers, primary and secondary overhead conductors, underground conductors, and distribution poles.

The resulting percentages of customer and demand-related costs were summarized by account and by secondary and primary voltage. For instance, total costs for secondary overhead lines would be allocated 73 percent on a customer basis and 27 percent on a demand basis. Similarly, more than half of the transformer costs would be allocated on a customer basis.

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[56] *See* Order No. PSC-17-0178-S-EI, issued May 16, 2017, in Docket No. 20160186-EI, *In re: Petition for rate increase by Gulf Power Company*; Order No. PSC-13-0670-S-EI, issued Dec. 19, 2013, in Docket No. 20130140-EI, *In re: Petition for rate increase by Gulf Power Company*; Order No. PSC-12-0179-FOF-EI, issued Apr. 3, 2012, in Docket No. 20110138-EI, *In re: Petition for increase in rates by Gulf Power Company*. We also approved MDS in TECO's 2018 and 2021 settlement agreements.

[57] Order No. PSC-02-0787-FOF-EI, issued June 10, 2002, in Docket No. 20010949-EI, *In re: Request for rate increase by Gulf Power Company.*

We do not find the testimony and evidence offered by TECO, FIPUG, and FEA to be persuasive in supporting the MDS methodology. We have previously denied the MDS methodology due to the hypothetical nature of relying on linear regressions.[58] In 2002, we found that "[t]he concept of a zero load cost is purely fictitious and has no grounding in the way the utility designs its systems or incurs costs because no utility builds to serve zero load."[59] We went on to explain that there was no real equipment that equated to the costs identified by the MDS methodology and that "MDS was rejected in the past for this very reason."[60] Similarly here, TECO witness Williams agreed that "TECO does not have transformers designed for zero load." The regression analysis is therefore of no probative value.

The record before us does not support allocating the majority of poles, transformers, and lines on a customer basis. There is not necessarily a one-to-one ratio between new customers on the one hand and poles, conductors, and transformers on the other. TECO witness Williams admitted that when a new customer is added to the system, transformers in the area would not need to be upgraded if they are of sufficient size to handle the new load. In other words, new residential customers may be added to existing transformers if there exists suitable capacity. FIPUG witness Pollock also admitted that the meter and service drop would not be used if a customer is not a customer. Even if one were to accept that the number of customers is a partial cause of transformer costs, in addition to load, the zero intercept analysis would allocate 65 percent of secondary transformers and 72 percent of primary transformers on a customer basis, which is a significant percentage of total costs. No witness before us justified why allocating 65 percent of secondary transformers or 72 percent of primary transformers are the precise portions of customer-related costs.

b. NARUC Cost Allocation Manual References to MDS

We next address TECO's, FIPUG's, and FEA's reliance on the NARUC cost allocation manual. This Commission noted in our 2002 Gulf order that the preface of the NARUC manual states three objectives: (1) it should be simple enough to be used as a primer on the subject of cost allocation yet offer enough substance for experienced witnesses; (2) it must be comprehensive yet fit in one volume; and (3) the writing style should be non-judgmental; not advocating any one particular method but trying to include all currently used methods with pros and cons.

In the 2002 Gulf order denying MDS, we found that the NARUC manual was "designed to educate, not mandate any particular methodology."[61] Furthermore, the 2002 Gulf order states that the NARUC manual "discusses only major methodologies and recognizes that no single costing methodology will be superior to any other and the choice of the methodology will depend on the unique circumstances of each utility."[62] Thus, while the NARUC manual is widely

[58] Order No. PSC-02-0787-FOF-EI, p. 76.
[59] *Id.*
[60] *Id.*
[61] Order No. PSC-02-0787-FOF-EI, p. 75.
[62] *Id.*

accepted as a reference guide for the assignment of costs, it is not mandated, and so our prior rationale expressed in the 2002 Gulf order remains valid.

c. Utility's Readiness to Serve Customers and Cost-Causation

TECO witness Williams testified that "MDS represents the readiness to serve a customer, not the capacity needed to meet a customer's peak demand requirements." He classified MDS costs as customer-related cost components because "[t]he readiness to serve costs are independent of how much electricity a customer consumes." In other words, TECO witness Williams asserts that customer-related costs are independent of kW and kWh usage and "generally vary with the number of customers on the system." However, TECO also explained that the primary factor considered in planning its distribution system is kW load requirements. Based on that response, kW demand requirements should receive a much larger weighting of the reason for installing distribution equipment, not the number of customers served, because of how TECO specifically plans its system.

We find the testimony and arguments raised by FL Rising/LULAC in opposition to the MDS methodology more persuasive and they share our concerns regarding the hypothetical nature of the TECO's linear regression analysis. FL Rising/LULAC witness Rábago testified that "TECO's MDS is based on a fantasty [sic] hypothetical distribution system sized to meet the demands of its customers when those customers use no energy and place no demand on the system. The MDS uses mathematical formula to extrapolate these artificial costs for a distribution system that is sized to meet load but then serves no load because it is installed 'in readiness.' TECO assigns those artificial costs to customers as customer costs."

Witness Rábago went on to point out that if the cost disappears because the customer leaves the system, then the cost is a customer cost. However, if the cost remains after a customer leaves the system, then cost is not a customer cost. This is the basis for the basic customer method, which FL Rising/LULAC witness Rábago believed is the most appropriate method of classifying customer-related costs.

Another limitation of the MDS methodology is that because some customers directly pay for extensions of the system with contributions in aid of construction (CIAC), not all of the distribution system is embedded in rates. By factoring in the entire length of the system, including facilities already paid for by customers through CIAC, the MDS analysis overstates the customer-related component. TECO confirmed that its CIAC policy ensures that customers pay for the cost of line extensions required to serve them when the expected revenues do not offset the cost of the extension.

TECO provided calculations in response to an interrogatory by FL Rising/LULAC comparing the revenue deficiency for all rate classes with and without MDS (assuming the 4 CP method). The results show that the residential and small commercial classes show a larger revenue deficiency with MDS, while the commercial and industrial classes show a smaller revenue deficiency with MDS. For the residential class, the revenue deficiency with MDS is \$196.8 million; without MDS it is \$151.0 million, a difference of \$45.8 million. The record evidence is clear that by classifying demand-related costs as customer-related, significantly more distribution plant costs would be assigned to the residential customers, however TECO has not met its burden for us to do so.

3. Conclusion

The record evidence does not support the MDS method. Based on the zero-intercept analysis, with the exception of secondary underground lines, almost half or more than half of the total costs for accounts 364 through 368, secondary and primary voltage level would be allocated based on the number of customers. Neither TECO, nor FIPUG, nor FEA, have provided sufficient evidence that number of customers has such a significant impact on TECO's method of planning and building its distribution system. Based on TECO's responses, it appears demand load requirements are the central criterion used in its system planning, not customers served. The parties supporting MDS also rely on the NARUC manual and the fact that MDS has been an accepted practice in Florida or other states. However, as stated earlier, the NARUC manual is a reference for assignment of costs and not mandated. While MDS has been approved in the past within the context of settlement agreements, the evidence in this record before us is not sufficient to justify MDS.

Distribution plant in accounts 369 (service drops) and 370 (meters) shall be classified as customer-related and distribution costs in accounts 364 through 368 (poles, overhead lines, underground lines, and transformers) as demand-related. The use of MDS is hereby rejected.

E. Allocation of Revenue Increase (Issue 74)

1. Summary of the Issue

This issue addresses the allocation of any revenue increase granted (as discussed in Issue 70) to the various customer classes, and is therefore largely dependent on the final revenue increase amount. In consideration of how to allocate a change in revenue requirement to the rate classes, one of our long standing practices is that, to the extent possible, the revenue increase should be allocated so as to bring all classes as close to parity as practicable. TECO witness Williams stated that the parity index is the ratio of each class's rate of return to the retail system rate of return. A parity index that is greater than one means that a class is providing a rate of return higher than the system average (i.e., the class is served above cost) while a parity index less than one indicates that a class is providing a rate of return below the system average (i.e., the class is served below cost). Parity is useful when determining the development of class revenue targets.

2. Analysis

FIPUG witness Pollock testified that the approved revenue requirement should be determined using an accepted class cost of service study, except when it would result in a class receiving an increase higher than 1.5 times the system average base revenue increase, and no class should receive a rate decrease. FEA stated that the revenue change should be allocated across rate classes based on the results of TECO's class cost of service study. FRF stated that it does not oppose TECO's proposed revenue allocation methodology for allocating any increase or decrease in revenue requirements to rate classes. OPC, Fuel Retailers, and the Sierra Club took no positions while Walmart adopted the position of FRF.

In allocating the increase to the various rate classes, TECO stated that it followed the Commission practice of gradualism, which limits the increase of each rate class to 1.5 times the system average increase in revenue, including adjustment clauses. The practice of gradualism, including limiting the increase to no greater than 1.5 times the system average percentage increase in total, has been affirmed in several prior Commission orders.[63]

3. Conclusion

The appropriate allocation of the change in revenue requirement, after recognizing any additional revenues realized in other operating revenues, should track, to the extent practical, the revenue deficiency of each class as determined from the approved cost of service study and move the classes toward parity to the extent practicable. The appropriate allocation compares present revenue for each class to the class cost of service requirement and then distributes the change in revenue requirements to the classes. No class should receive an increase greater than 1.5 times the system average percentage increase in total, and no class should receive a decrease. We find that TECO's revised MFR Schedule E-8 as filed on December 9, 2024, reflects our vote on this issue.

F. Delivery Voltage Charge (Issue 75)

1. Analysis and Conclusion

A delivery voltage credit is included in the General Service-Demand, Time-of-Day General Service-Demand, Standby and Supplemental Demand Service, and Time-of-Day Standby and Supplemental Demand Service rate classes. When a customer under the standard rate takes service at primary voltage level or at subtransmission or higher voltage, a per kilowatt discount is applied. TECO's calculations of the delivery voltage credits are shown in MFR Schedule E-14, Supplement B, page 6 of 12. The discount is based on distribution or subtransmission investment the customer does not need by taking service at a higher voltage. The proposed demand charge credits are included in the proposed tariffs.

FL Rising/LULAC stated, "No," in its post-hearing brief but did not provide any additional argument, while no other intervenor took a position on this Issue.

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[63] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 20080317-EI, *In re: Petition for rate increase by Tampa Electric Company*, p. 87; Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company,* p. 179; Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 20070304-EI; *In re: Petition for rate increase by Florida Public Utility Company*, p. 63.

We therefore approve the delivery voltage credits contained in the tariffs in Attachment F of this Order.

G. Service Charges (Issue 76)

1. Analysis

TECO witness Williams stated in his direct testimony that TECO projected an increase of $2,976,000 to service charge revenues, indicated in MFR Schedule E-13b. TECO filed MFR Schedule E-7 and Time-of-Motion study, in which it justified the proposed increases by showing a cost breakdown for the development of each service charge. MFR Schedule E-7 detailed the amount of time spent to complete each task, versus the cost of each task to TECO in the form of an hourly rate. MFR Schedule E-7 showed that TECO is currently charging below cost for each basic service charge. TECO witness Williams explained in his direct testimony that TECO proposed a gradual increase. TECO also stated that with the exception of the return check charge, the unit cost "significantly exceeded TECO's currently approved rate. TECO is proposing to employ rate gradualism and cap the service charge increases at 50 percent of the currently approved rate."

Table 16 displays a comparison of the service charges; each charge is discussed individually below.

Table 16
Service Charge Comparison - 2025

	Current Charge	Proposed Charge	Actual Cost	Commission Approved
Initial Connection	$112.00	$168.00	$330.73	$168.00
Reconnection (Nonpayment)	$12.00	$18.00	$20.42	$18.00
Reconnection	$10.00	$15.00	$22.73	$15.00
Field Visit	$25.00	$37.00	$78.75	$37.00
Temporary Overhead and Underground	$320.00	$480.00	$567.52	$480.00
Meter Tampering	$50.00	$75.00	$187.26	$75.00

a. Initial Connection

TECO proposed an increase to $168.00 from the current charge of $112.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 1 of 7. The expenses to TECO comprise of customer service expenses, field labor, administrative expense, and vehicle cost.

FL Rising/LULAC witness Rábago argued in his direct testimony that TECO should reduce their initial connection charge by 80 percent, citing that electric service is necessary for survival and that the initial connection fees requested by TECO are "out of step" with other utilities in Florida. Witness Rábago also argued that residential customer costs should only reflect the equipment and infrastructure used to connect residential customers, and should not reflect the higher-cost equipment and infrastructure used to connect larger power users. TECO's proposed initial connection charge is higher than the currently approved charges for FPL ($13), DEF ($58), and FPUC ($61).

However, in TECO's filed MFR Schedule E-7, page 1 of 7, TECO included a breakdown of the costs to connect a new customer. MFR Schedule E-7 detailed the tasks required, the amount of time to complete each, and the hourly rate for the employee(s) involved. As shown in Table 16, TECO's proposed charges are set below costs. TECO explained that for the initial service connection charge, the cost is higher than the currently approved rate, thus TECO proposed to increase the charge using a "gradualistic approach."

b. Reconnection of Service at Meter (Nonpayment)

TECO proposed an increase to $18.00 from the current charge of $12.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 3 of 7. The expenses to TECO comprise of customer service, field labor, administrative expense, customer noticing, and vehicle cost.

c. Reconnection of Service

TECO proposed an increase to $15.00 from the current charge of $10.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 2 of 7. The expenses to TECO comprise of customer service, field labor, administrative expense, and vehicle cost.

d. Field Visit

TECO proposed an increase to $37.00 from the current charge of $25.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 5 of 7. The expenses to TECO comprise of customer service, field labor, administrative expense, customer noticing, and vehicle cost.

e. Temporary Overhead and Underground

TECO proposed an increase to $480.00 from the current charge of $320.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 7 of 7. The expenses to TECO comprise of customer service, field labor, administrative expense, and vehicle cost.

f. Meter Tampering

TECO proposed an increase to $75.00 from the current charge of $50.00. TECO has provided a breakdown of the costs in MFR Schedule E-7, page 6 of 7. The expenses to TECO comprise of customer service, field labor, administrative expense, vehicle cost, and a meter security lock.

2. Conclusion

TECO has provided cost justification for their proposed service charges and explanation about capping the increase at 50 percent. Therefore, we find the requested increases are appropriate and reflect the record evidence. The appropriate service charges are $168.00 for initial connection, $18.00 for reconnection of service which has been disconnected at the meter due to nonpayment, $15.00 for reconnection of service which has not been disconnected due to nonpayment, $37.00 for field visit, $480.00 for temporary overhead and underground, and $75.00 for meter tampering.

H. Emergency Relay Power Supply Charge (Issue 77)

1. Analysis

TECO's emergency relay power supply option was originally approved in Order No. PSC-98-0508-FOF-EI, to provide a higher-than-standard level of reliability for commercial customers to prevent more than a few seconds' of service interruption.[64] Customers subscribing to relay service are connected to a primary distribution circuit and a back-up distribution circuit (or trunk line). The back-up distribution circuit connected to a back-up substation, on which capacity is reserved for relay service customers. When an outage is sensed on the primary line, a switch will change power to the back-up circuit.

Relay service customers pay a CIAC and a monthly charge that is calculated in part using a per kW charge. TECO's MFR Schedule E-14, Supplement B, page 7 and 8 of 12, provides a breakdown of the costs and methodology used to calculate the charges. TECO proposed an increase from $50.27 per kW to $62.51 per kW for the CIAC of trunk line capacity and an increase in the monthly emergency relay charge from 0.68 cents per kW to $1.02 per kW. Costs included in the calculations are distribution substation plant, primary distribution plant, and associated O&M costs. We find that TECO's methodology to calculate emergency relay service charges is appropriate; however, the charges are subject to change based on the Commission vote in other Issues.

2. Conclusion

TECO proposed methodology to calculate emergency relay power supply charges is appropriate and approved. We therefore approve the emergency relay power charges, as refiled by TECO on December 9, 2024 pursuant to our vote, and contained in the tariffs in Attachment F of this Order.

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[64] Order No. PSC-98-0508-FOF-EI, issued April 13, 1998, in Docket No. 19980131-EI, *In re: Petition by Tampa Electric Company for approval of emergency relay power supply service option for general service customers*.

I. Basic Service Charges (Issue 78)

1. Analysis and Conclusion

The final basic service charges, or customer charges, are a fall-out issue dependent upon our decisions related to revenue requirement and cost of service.

TECO proposed to increase the residential basic service charge (which is billed as a daily charge) from $0.71 per day ($21.30 per month) to $1.07 per day ($32.10 per month). FL Rising/LULAC witness Rábago testified that the Commission should reject TECO's proposed customer charges and instead approve a customer charge of no more than $0.43 per day ($12.90 per month), based on a re-calculation of customer costs that exclude the MDS method. As discussed in Issue 73, FL Rising/LULAC object to the MDS method.

The basic service charges, in combination with the demand charges and the energy charges, are designed to allow TECO to recover the total Commission-approved revenue requirement. We thereby approve the basic service charges reflected in Attachment F as they encompass our approved revenue requirement and cost of service methodology.

J. Demand Charges (Issue 79)

1. Analysis

The final demand charges are a fall-out issue dependent upon our decisions related to revenue requirement and cost of service.

Per the current rate schedules, TECO customers are enrolled in a demand rate class and issued a demand meter when they consume more than 9,000 kWh in any one billing period out of the past 12 billing periods. Demand is determined using the customers' 30-minute interval with the highest demanded kW. Customers will be entered into a large demand rate class when their demand consumption reaches more than 1,000 kW over any 30-minute interval at any point of their billing period, for at least one billing period in the past 12 billing periods.

TECO provided its proposed demand charges in MFR Schedule E-13c, pages 5–18. TECO witness Williams stated in his direct testimony that demand cost is a function of the capacity of plant and maximum kW of power demanded by customers. Witness Williams further stated that demand costs occur at the production, transmission, and distribution level.

FEA witness Gorman addressed in his direct testimony the rate design for the General Service Large Demand – Primary (GSLDPR) and Time of Day General Service Large Demand – Primary (GSLDTPR) rate schedules. These rate schedules are applicable to customers with a registered demand of 1,000 kilowatt or above once in the last 12 months.

With respect to those two rate schedules, witness Gorman stated that TECO is over-recovering on the energy charges and under-recovering on the demand charges. Based on information provided in TECO's cost of service study and derivation of unit costs, witness Gorman provided in his direct testimony a table demonstrating a breakdown of TECO's revenue requirement costs for its GSLDPR rate class. Based on the information included there, witness Gorman concluded that 86.3 percent of TECO's revenue requirement costs are demand-related. Witness Gorman compared these costs to the demand revenue requirement illustrated in another table in his direct testimony, which shows that only 67.6 percent of GSLDPR revenues are collected through demand charges. Witness Gorman concluded, based on his analysis, that TECO should increase demand charges and reduce energy charges.

We do not dispute the information provided by FEA witness Gorman regarding the GSLDPR rate class; however, following strict unit cost in setting demand rates may make it difficult to maintain rate design goals and principles. Furthermore, a significant increase in the demand charges could adversely impact low load factor customers.

TECO witness Williams addressed FEA witness Gorman's argument in his rebuttal testimony, disagreeing with FEA witness Gorman's assertion that TECO should increase demand charges for the GSLDPR rate class to match unit cost. TECO witness Williams agreed that FEA witness Gorman had correctly identified a mismatch between unit cost and customer cost, but stated that this was done intentionally and in accordance with terms that FEA agreed to in the 2021 Settlement Agreement. TECO witness Williams also stated that he did not support the GSLDPR energy charge being lower than it currently is.

FL Rising/LULAC in its post-hearing brief addressed the residential energy and demand charge; however, residential customers are not billed a demand charge. No other party took a position on this issue.

2. Conclusion

We find that the methodology used by TECO to determine the demand charges is appropriate. The appropriate rate design for the demand charges is discussed in conjunction with the appropriate rate design for the energy charges decided in the following issue, Issue 80. The demand charges, in combination with the basic service charges and the energy charges, are designed to allow TECO to recover the total Commission-approved revenue requirement. The demand charges reflected in Attachment F encompass our approved revenue requirement and cost of service methodology. We therefore approve the demand charges contained in the tariffs in Attachment F of this Order.

K. Energy Charges (Issue 80)

1. Analysis and Conclusion

Energy charges refer to the cents paid by a customer per kWh. This is another fall-out issue dependent upon our decisions related to revenue requirement and cost of service, including demand revenue and demand charges.

TECO witness Williams addressed the energy charges in his direct testimony and in MFR Schedule E-13c. These costs are allocated using a 4 CP method, which we addressed in Issues 71 and 72. OPC stated that the energy charges should reflect all adjustments to ROE as recommended by OPC as approved by the Commission. This is discussed in depth in Issue 39 where we address the appropriate Return on Equity. FL Rising/LULAC opposed the proposed energy charges, stating in their prehearing statement that the residential energy charge should be reduced to 8.59 cents per kWh for the first 1,000 and 9.52 cents per kWh for all subsequent usage.

The energy charges, in combination with the basic service charges and the demand charges, are designed to allow TECO to recover the total Commission-approved revenue requirement. The energy charges reflected in Attachment F encompass our approved revenue requirement and cost of service methodology. We therefore approve the energy charges contained in the tariffs in Attachment F of this Order.

L. Lighting Service (Issue 81)

1. Analysis and Conclusion

The appropriate Lighting Service rate schedule charges are a fall-out issue dependent upon our decisions related to revenue requirement and cost of service. We therefore approve the charges provided in the tariffs in Attachment F to this Order.

M. Standby Service (Issue 82)

1. Analysis and Conclusion

The appropriate Standby Services (SS-1, SS-2, SS-3) rate schedule charges are a fall-out issue dependent upon our decisions related to revenue requirement and cost of service. We therefore approve the Standby Services charges contained in the tariffs in Attachment F of this Order.

N. Time-of-Day Periods (Issue 83)

1. Analysis

TECO witness Williams explained the proposed changes to TECO's time-of-day periods for each of its optional time-of-day rate schedules available to commercial or industrial customers. Currently, the on-peak hours vary between the summer and winter season. Specifically, the current peak hours are noon to 9 p.m., Monday through Friday, during April 1 through October 31. For the months November 1 through March 31, the on-peak hours are 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. All other weekday hours and all hours on weekends and holidays are off-peak hours.

TECO witness Williams stated that TECO is proposing to add a super off-peak period and to remove the seasonality of its time-of-day periods. The proposed year-round peak period is 6 a.m. to 10 a.m. and 5 p.m. to 9 p.m. The proposed super-off period is 10 a.m. to 5 p.m.; the off-peak period would be all other hours. The cents per kWh energy charges vary between the different peak periods, with the charge being the highest during the peak hours and the lowest during the super-off-peak hours.

The current and proposed time-of-day periods are summarized in the table below.

Table17
Current and Proposed Time-of-Day Periods

	Current		Proposed
Period	April – October	November - March	Year-Round
Peak	Mon – Fri 12 p.m. (noon) – 9 p.m.	Mon – Fri 6 a.m. – 10 a.m. 6 p.m. – 10 p.m.	Mon – Fri 6 a.m. – 10 a.m. 5 p.m. – 9 p.m.
Off-Peak	All other weekday hours and holidays	All other weekday hours and holidays	Sat – Sun 12 a.m. – 10 a.m. 5 p.m. – 12 a.m.
Super Off-Peak	n/a	n/a	Mon – Sun 10 a.m. – 5 p.m.

TECO witness Williams testified that TECO has not changed the time periods for its optional time-of-day rate schedules since the 1980s. Witness Williams asserted that with TECO's recent and continued investment in renewable generation assets, TECO's hourly cost profile has changed and this new structure will better align with TECO's hourly cost profile. Witness Williams stated that eliminating the seasonal change in its pricing periods was designed to achieve simplicity and understandability by allowing customers to more effectively set their operations.

To derive its proposed base rates for its optional time-of-day rate schedules, TECO used a marginal cost methodology to help determine its time periods and the rate differentials. TECO ensured that the rates were revenue neutral to 2024 base rates. This means that the average customer on a time-of-day rate schedule would not experience an increase or decrease to their bill because of the time-period change; the increase to a customer's bill is a function of TECO's request to increase base rates.

To further support the proposed time-of-day changes, TECO witness Williams stated that the super off-peak period was added due to the change in TECO's hourly cost profile. Today, TECO continues to invest in renewable generation assets, primarily solar assets. The cost to generate a MWh in the early afternoon relative to other time periods is generally cheaper because of TECO's solar assets.

TECO explained that to communicate the proposed changes to its time-of-day rate periods to its customers, TECO's Account Management team will reach out to mid-market and large commercial and industrial customers currently on a time-of-day rate. Additionally, TECO will program an Important Message to appear on all commercial and industrial bills (all eligible customers) creating awareness of the time-of-day rate change.

FIPUG witness Pollock disagreed with TECO on this issue. FIPUG stated that TECO's proposed time-of-day periods, which include very low super off-peak energy charges, would be unique in Florida. No other investor-owned utility in Florida offers a super off-peak period that encourages electricity usage during hot summer afternoons when TECO (and Florida utilities generally) regularly experiences its system peaks. Witness Pollock also noted that TECO's proposed super-off peak period would coincide with daytime hours when most of the system peaks generally occur. Finally, witness Pollock asserted that the proposed super-off-peak period is also based on an assumption that TECO will continue to expand its investment in renewable generating assets.

FIPUG witness Pollock presented an analysis showing marginal energy costs by hour by month. Based on the analysis, witness Pollock concluded that with exception of April and May, the marginal energy costs are not consistently low during TECO's proposed super off-peak period. Witness Pollock concluded that TECO's proposal is dramatic; low energy prices during the day send the wrong price signal because peak demand occur during daytime houses; and it is premature to premise a major rate change based on TECO's investment in solar.

TECO witness Williams attempted to address FIPUG's assertion by stating that customers will only need to reset their operations once to reflect the new time periods, instead of adjusting them seasonally. Furthermore, TECO's business and industrial customers taking service under an optional time-of-day rate are generally high load factor customers, meaning their energy consumption level does not vary substantially, relative to their demand, over time.

Witness Williams also disagreed with witness Pollock's analysis showing that "marginal energy costs are not consistently low" during the proposed super off-peak period because witness Pollock presented a heat map of the average marginal cost by hour within each month but failed to show the average marginal energy cost over the course of a year. Witness Williams testified that while witness Pollock is correct that there are hourly variations in marginal pricing, TECO is not proposing real-time pricing or different rates for each day and/or hour of the year in this rate case. Instead, TECO proposed three time-of-day time periods. The proposed super off-peak period has an average marginal energy cost that is cheaper than the proposed off-peak and peak periods over the course of a year.

Witness Williams presented TECO's average marginal energy costs per kWh during the three proposed periods. The marginal energy costs shown in Exhibit 152 have been granted confidentiality.[65] The analysis shows that the average marginal energy costs, over the course of a

[65] Order No. PSC-2024-0310-CFO-EI, issued August 7, 2024, in Docket No. 20240026-EI, *In re: Petition for rate increase by Tampa Electric Company.*

year, are the lowest during the proposed super off-peak period and highest during the on-peak period. TECO also provided its most recent projection of 8,760 marginal energy costs to support its assentation that because of the change in generation mix, marginal costs during the day have decreased.

As witness Pollock pointed out, the proposed super off-peak period would overlap during the hours of noon to 5 p.m. with the current peak period, and we agree with FIPUG that this does appear to be a drastic change in time-of-day periods. The average marginal energy costs for 12 months are lowest during the super-off peak, however, we do not find that the differences in marginal cost are sufficient to justify this significant change in time-of-day periods. Furthermore, TECO's analysis does not support elimination of the seasonal winter/summer time-of-day periods. Based on the marginal energy costs presented by TECO, the average super-off peak marginal cost during the summer months April through October are not the lowest (when compared to the off-peak and on-peak periods). Therefore, we find that having a super-off peak period in the afternoon during the summer months is not supported by the evidence.

2. Conclusion

Currently, customers on the optional time-of-day rate schedules are encouraged through price signals to conserve during the summer noon to 5 p.m. hours. Changing the price signal to add load during the same period does not appear reasonable. We agree with TECO that time-of-day periods have been determined in the 80s and that changes in the generation mix may warrant modifications to the time-of-day periods; however, TECO's proposed elimination of the seasonal rates and addition of a super off-peak period during the hours 10 a.m. – 5 p.m. (year round) which are not sufficiently supported at this time and are hereby denied.

O. Non-Standard Meter Rider (Issue 84)

1. Analysis and Conclusion

TECO included in its MFR schedules a supplemental opt-out study that calculated the incremental costs to serve customers taking service under the optional Non-Standard Meter Rider (NSMR) tariff. The NSMR tariff is a smart meter opt-out tariff and was approved in Order PSC-2019-0112-TRF-EI.[66] Customers who choose to take service under the NSMR tariff receive a meter that does not utilize radio frequency communications or is otherwise required to be read manually. TECO's study indicated that the cost of installation and maintenance of NSMR meters would be lower than the rates currently charged to customers under that tariff.

The currently approved optional NSMR tariff includes a \$100.00 initial one-time set-up fee and a \$0.67 daily rate. TECO's opt-out study shows that the one-time charge cost consists of administrative costs and installation costs to enroll the customer in the program and set up the meter, while its monthly costs consist of meter reading and IT system maintenance expenses. TECO's cost for the one-time set up charge is shown to be \$44.95, while the daily cost is shown

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[66] Order No. PSC-2019-0112-TRF-EI, issued March 25, 2019, in Docket No. 20190024-EI, *In re: Petition for approval of smart meter opt-out tariff, by Tampa Electric Company.*

to be $0.6239 (or $19.13 per NSMR customer per month). TECO stated that the need for IT development and analysis of meter reading schedules was found to be less labor-intensive than originally estimated. However, TECO did not file a revised NSMR tariff (Tariff Sheet No. 3.280) to reflect a decrease in cost to customers under the NSMR rider. TECO stated that the NSMR charge is used to address costs of Advanced Meter Reading (AMR) meters, and any remaining money is used to reduce RS, GS, and GSD rate classes. TECO stated that its AMI provide value to customers, with a 98 percent success rate that reduce personnel visits to accomplish functions that can be handled remotely. TECO further stated in its post-hearing brief that this is an optional program and no party presented evidence challenging TECO's position.

No modification to the NSMR was proposed. We find that the NSMR tariff remains appropriate and no modifications need to be made.

P. Budget Billing Program (Issue 85)

1. Analysis

TECO witness Williams testified that the tariff language is being rewritten to reflect changes to the methods used to calculate bills for participants in the Budget Billing Program. The intent of the program is to provide customers with similar charges from month to month. Bills are currently calculated on a "backward-looking" basis with annual recalculations, which do not properly take into account fuel price volatility, base rate increases, storm restoration costs, and customer increases in consumption. Witness Williams stated that the current methods of calculation have subjected participants to irregular billing. Witness Williams discussed some of the proposed changes in his direct testimony, which are found in full in the proposed modified tariffs. TECO proposed a quarterly recalculation, rather than annual, with the ability to recalculate more frequently if deemed necessary by prices or consumption. TECO also proposed to show any deferred balance on the customer's bill. TECO proposed that the deferred debit balance will be applied after a periodic review, while a deferred credit balance will be applied during an annual true-up period. Witness Williams stated in his direct testimony that these changes will prevent large changes.

FL Rising/LULAC took an opposing stance on this Issue, although they did not elaborate on why. Our staff requested additional information from TECO regarding the revisions to the Budget Billing Program. The proposed modified tariffs stated that the customer's bill may be recalculated outside of the quarterly review period at the customer's request. No other party took a position on this Issue.

2. Conclusion

We have reviewed the proposed modifications to the Budget Billing Program and find that they are appropriate and supported by the record evidence. The revisions to the program are beneficial to customers and will serve the program's intended purpose of keeping customer bills as consistent as possible. We hereby approve of the proposed tariff modifications to the Budget Billing Program, indicated on the Fifth Revised Tariff Sheet No. 3.020.

Q. General Liability and Customer Responsibilities (Issue 86)

1. Analysis

TECO witness Williams explained that TECO is proposing to provide greater clarity regarding customer responsibilities and Company responsibilities with the proposed tariff revisions. The proposed language can be seen in TECO's proposed Original Sheet No. 5.081. Proposed tariff Sheet No. 5.070 adds additional clarity regarding customers' responsibilities. No other party took a position on this Issue.

2. Conclusion

We approve the proposed tariff modifications regarding general liability and customer responsibilities (Fifth Revised Tariff Sheet No. 5.070 and Original Tariff Sheet No. 5.081) because the revisions provide greater clarity regarding customer responsibilities and Company responsibilities.

R. Contribution in Aid of Construction (Issue 87)

1. Analysis

TECO proposed a modification to its CIAC tariff that would allow customers to enter into alternative payment arrangements. TECO witness Williams explained that TECO has historically collected CIAC prior to commencing construction, which protects the general body of ratepayers from the risk of non-payment. Witness Williams explained the need for alternative payment arrangements to accommodate some customers, such as governmental customers for example. The witness stated that governmental customers are bound to payment processing schedules that did not align with upfront payment of CIAC. Furthermore, witness Williams stated TECO would put procedures in place to monitor and mitigate risk associated with alternative payment arrangements to the general body of ratepayers. In addition, TECO will establish a four-Director committee that would monitor outstanding CIAC payments and ensure that any outstanding CIAC payments are collected.

TECO witness Williams stated that TECO will extend alternate payment arrangements, i.e. CIAC, without an upfront payment, to private customers as well as the aforementioned governmental customers. TECO does not have a formula or model used to calculate a customer's risk of nonpayment, but takes a customer's payment history and standing with TECO into account. TECO also will cap CIAC without upfront payment at $1 million. OPC and Walmart argued in their briefs that the modifications to CIAC should be approved so long as the installment payments of CIAC are fully credited as a reduction of rate base once the agreement to pay CIAC is completed, even if there is an outstanding balance. FRF did not oppose the proposed tariff modification.

2. Conclusion

We acknowledge that the proposed alternate payment method introduces increased risk to the general body of ratepayers. By completing work before receiving payment, TECO risks incurring bad debts. However, TECO has proposed methods of vetting customers as well as ensuring continued payment. We find these methods to be appropriate, and find the risk is outweighed by the benefits of allowing more customers to utilize CIAC. Overall, we find the record evidence supports that the proposed alternate payment arrangements are appropriate. The revised Fifth Revised Tariff Sheet No. 5.105 is reasonable and supported by the record evidence and is hereby approved.

S. Economic Development Rider (Issue 88)

1. Analysis

TECO's Economic Development Rider (EDR) was first introduced as a three-year pilot in the stipulation and settlement agreement approved by this Commission in TECO's 2013 base rate proceeding.[67] In Order No. PSC-16-0210-TRF-EI, we extended the EDR tariff on a permanent basis.[68] The EDR requires a five-year contract and provides base rate discounts for new business that meet certain requirements such as minimum size, job creation, and verification that the availability of the EDR is a significant factor in the customer's location or expansion decision. The EDR is not available to existing load.

TECO witness Williams testified that TECO wants to remain competitive in attracting new business and companies are becoming more efficient in their electric consumption and labor usage.

The proposed EDR program changes are:

(1) The minimum qualifying load will be 300 kW instead of 350 kW.
(2) The required new full-time equivalent jobs in TECO's service area will be 20 instead of 25; or
(3) A customer will qualify for the EDR if the customer makes $500,000 or greater capital investment in TECO's service area and increases full time equivalent jobs.
(4) A customer may request an effective date of the EDR which is no later than two years after the Customer Service Agreement is approved and signed by the Company.

The EDR has no impact on the RS, GS, GSLDPR, GSLDSU, or LS rate classes' revenue requirement. The EDR increases the GSD rate class's revenue requirement in the test year by $89,106.

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[67] Order No. PSC-13-0443-FOF-EI, issued September 30, 2013, in Docket No. 20130040-EI, *In re: Petition for rate increase by Tampa Electric Company.*
[68] Order No. PSC-16-0210-TRF-EI, issued May 25, 2016, in Docket No. 20160059-EI, *In re: Petition to extend economic development rider on a permanent basis, by Tampa Electric Company.*

TECO explained that the proposed reduction from 350 kW to 300 kW is a reasonable threshold to capture the declining average use trends, including customers reducing their brick-and-mortar footprint and continued investment in more efficient equipment such as LED lights and motion sensors. Types of customers who would use 300 kW could be healthcare centers, a grocery store, a hardware store, a small call center, or a small manufacturer. The 300 kW minimum load is an amount that must be achieved at least once within a year for each year that the participating customer takes service under the EDR. Currently, at the 350 kW requirement, TECO has eight customers enrolled in its EDR program in which each company is required to create 25 jobs at a minimum.

TECO also stated that some eligible customers who elect to participate do not always ramp up their kW load to full capacity right away and may not meet the minimum requirements until they have ramped up their operations. For this reason, TECO may attract commercial customers to the area by delaying the full implementation of the credit for up to two years. A customer may request this option if they believe their build out and ramp up will take some time rather than it immediately occurring.

2. Conclusion

This Commission has a long history of approving economic development tariffs for electric utilities and FL Rising/LULAC have provided no evidence as to why the EDR should be stricken. The proposed EDR modifications will allow TECO to remain competitive in attracting new commercial and industrial customers to its service area. Therefore, the proposed modifications to the EDR tariff included in the Third Revised Tariff Sheet Nos. 6.720, 6.725, 6.730 are hereby approved.

T. Lighting Wattage Variance (LS-1) (Issue 89)

1. Analysis

TECO proposed a change in the lighting wattage variance, contained in the Eleventh Sheet No. 6.809, to twenty-five percent, from the previous variance of ten percent. TECO witness Williams explained in his direct testimony that LED technology is continuing to develop and products are becoming more efficient, reducing the wattage while increasing the lumen output. Witness Williams stated that the larger variance amount will allow TECO to more accurately calculate monthly energy consumption while minimizing impacts to customers. No other party took a position on this Issue.

2. Conclusion

We find that the proposed changes to the LS-1 lighting wattage variance are reasonable. Therefore, we find that the lighting wattage variance should increase to 25 percent, from the previously approved variance of 10 percent. We hereby approve those modifications to LS-1 regarding lighting wattage variance.

U. Monthly Rental Factors (LS-2) (Issue 90)

1. Analysis

TECO witness Williams stated in his direct testimony that TECO's LS-2 rate schedule was introduced in 2022. TECO's current LS-2 rate schedule offers 20-year contracts with one monthly rental factor of 0.93 percent, calculated to recover the net present value of the asset(s) over a 20-year-period, allowing TECO to fully recover the assets during the rental period. To offer customers more flexibility, regarding the term of the agreement, TECO proposed to offer rental terms between 1 and 25 years, with adjusted rental factors to permit TECO to recover its assets accordingly. According to the LS-2 tariff, the monthly charge to the customer is calculated by applying the corresponding LS-2 monthly rental factor to the in place value of the customer specific lighting facilities.

2. Conclusion

We find that offering a wider range of rental term lengths is fair and reasonable. TECO indicates that the factors allow it to offer more options to customers while also permitting TECO to recover its assets in full. The proposed arrangement ensures that the general body of ratepayers is protected from subsidizing the rental costs, which will be paid by cost-causing customers only. We therefore approve of the proposed LS-2 monthly rental factors, as shown in the tariffs in Attachment F to the order, which shall permit customers to contract lighting service for a period between 1 and 25 years.

V. Termination Factors for Long-Term Facilities (Issue 91)

1. Analysis

Proposed Fifth Revised Tariff Sheet No. 7.7.65 provides the monthly rental and termination factors for long-term facilities. These factors apply if a customer and TECO enter into a facilities rental agreement pursuant to which TECO is renting facilities to the customer who requested them. The customer is required to pay a monthly rental factor that is applied to the in-place value of the facilities rented. The term of the agreement is 20 years; the termination factors apply if the agreement is terminated early.

The current monthly rental factor is 0.93 percent and TECO is proposing to increase the monthly rental factor to be applied to the in-place value of the facilities to 0.99 percent per month plus applicable taxes. Pursuant to the Fifth Revised Sheet No. 7.765, if the long-term rental agreement for Facilities is terminated, a termination fee shall be computed by applying the termination factors to the in-place value of the facilities based on the year in which the Agreement is terminated. TECO's calculations of the monthly rental and termination factors for facilities rental agreement are shown in Schedule E-14, Supplement B, pages 11–12 of 12.

2. Conclusion

TECO's calculations of the monthly rental and termination factors for facilities rental agreement are appropriate and we therefore approve the factors shown on Fifth Revised Tariff Sheet No. 7.765 included in Attachment F of this Order.

W. Non-Rate Related Tariff Modifications (Issue 92)

1. Analysis

TECO proposed non rate-related tariff modifications to update basic information such as revision number, page number, President's name, and the effective date. We have reviewed these proposed changes and find they are vital to the legibility and readability of the tariffs.

TECO also proposed a modification to Seventh Revised Sheet No. 5.130, which addresses customer deposits. In particular, the language regarding return of deposit money following termination of service. An agency may pay the deposit fee on behalf of a customer for a number of reasons, and TECO wished to clarify the language to allow the deposit fee to be refunded to the agency when appropriate. We find this change to be fair and reasonable because it allows deposits to be returned to an agency depending upon the circumstances of the customer assistance provided.

2. Conclusion

We find that TECO's explanation is reasonable and the non-rate related tariff modifications are hereby approved.

X. Approval of Tariffs (Issue 93)

1. Analysis and Conclusion

This is a fall-out issue. We have reviewed the revised cost of service study and associated tariffs for consistency with our approved revenue requirement. The documentation provided by TECO is in accordance with the Commission vote from the December 3, 2024 Special Agenda Conference. We therefore approve the tariffs as provided in Attachment F of this Order.

X. 2026 and 2027 Subsequent Year Adjustments

This section focuses on what, if any, adjustments should be made to the Utility's revenue requirement in each of the two years subsequent to the 2025 Projected Test Year. The issues contained in this section were identified as issues 94 through 110 in the Prehearing Order. First we discuss the considerations that go into making such a determination (Issue 94), and then we decide which projects proposed by TECO merit a Subsequent Year Adjustment (SYA) in either 2026 or 2027 in the remaining issues.

A. Subsequent Year Adjustments (SYA) – Legal Framework (Issue 94)

1. Analysis

An SYA is a regulatory mechanism that involves an incremental adjustment to a company's revenue requirement. In a rate proceeding, the revenue requirement is established based on a projected test year, and an SYA would be an incremental adjustment (increase) to the revenue requirement in the year or years following the projected test year.

The Commission's authority to implement an SYA has been previously confirmed by the Legislature and by the Florida Supreme Court.[69] Pursuant to Section 366.076(2), F.S., we may adopt rules that provide for incremental adjustments in rates for periods subsequent to the period new rates are to be in effect. Accordingly, our Rule 25-6.0425, F.A.C., reflects that in a full revenue requirements proceeding we may approve incremental adjustments in rates for periods subsequent to the initial period in which new rates will be in effect.

Because SYAs apply to projects that are implemented during and beyond the projected test year, as opposed to projects already in operation, they are inherently more speculative and, therefore, require additional scrutiny. Consistent with our above authority, a company has the burden to prove by a preponderance of the evidence that an SYA is needed or necessary to implement in the current proceeding. In this case, TECO's proposed 2026 and 2027 SYAs reflect two types of requests: the annualization of projects placed into service in a period prior to the proposed SYA and projects placed into service subsequent to the projected test year.

a. TECO's Request

TECO's petition contains two types of requests. The first type of request is the annualization of projects that were placed into service in a period prior to the proposed SYA. For example, the 2026 SYA reflects the annualization of projects placed into service in 2025 and the 2027 SYA reflects the annualization of projects placed into service in 2026. A projected test year in a rate case reflects a 13-month average for all rate base components. Therefore, the revenue requirement from that period will not reflect the full amount of revenues, expenses, and rate base associated with projects if they are in service for the entirety of that timeframe. For significant and material plant projects (i.e., not typical additions that are expected in a typical year), this could potentially reduce a company's ability to recover its investment, especially for those placed into service towards the end of a projected test year.

The second type of request made by TECO in this case are projects that will be placed into service subsequent to the projected test year. Specifically, the 2026 and 2027 SYAs reflect the 13-month average of projects placed into service in 2026. The Commission has only rarely

[69] *See* Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 20080677-EI, *In re: Petition for rate increase for Florida Power & Light Company,* and Docket No. 20090130-EI, *In re: Depreciation and Dismantlement study by Florida Power and Light Company*.

considered base rate increase requests with SYAs outside the context of settlement agreements.[70] In evaluating settlement agreements, the Commission first focuses on the major issues in the settlement by considering all of the evidence presented at a hearing on the settlement and making ultimate findings of fact based on the evidence in the record that is supported by a preponderance of the record evidence. Secondly, in light of findings of fact, the Commission determines whether the settlement is in the public interest and results in rates that are fair, just, and reasonable.

In the instant docket, TECO's rate request is a fully litigated case before the Commission for resolution and the proposed SYAs are major issues in the case. Therefore, in the context of a fully litigated case, each SYA project must be evaluated. In so doing, we find that we should consider certain factors for evaluating SYA projects in light of TECO's specific requests in this proceeding.

b. The Parties' Proposed Criteria for Evaluating SYAs

There is competing testimony and argument as to what criteria should be considered by the Commission when evaluating TECO's SYA requests in this proceeding. OPC's position, adopted by FIPUG and Walmart, is that an SYA project should not be allowed absent compelling circumstances, and should not be necessary if the test year is chosen appropriately. OPC also proposed that we weigh whether TECO, in the absence of a SYA, would earn below the approved range during the years immediately following a rate case and whether TECO has demonstrated the need for generation or other facilities in the subsequent year. OPC also proposed that an SYA project be a discrete, material, generation-type capital project. Similarly, FL Rising/LULAC's position, adopted by Sierra Club, is that SYA projects should be limited to specific, large, singular generation investments and should include customer protections.

On the other hand, TECO argues that there is nothing in the applicable statutes or rules that limits the Commission's consideration to these types of projects described by the intervenors, and that its requests should be accounted for in SYAs for 2026 and 2027 because they are in fact "major projects." TECO asserts placing them in service will have a material impact on the company's ability to earn within its authorized range of returns and will mitigate the company's need for successive general rate increases.

2. The Commission's Critieria for TECO's SYAs

a. Annualization of Projects Placed into Service in a Period Prior to the proposed SYA

We find that TECO's request to annualize certain projects is reasonable in specific circumstances. We find that annualization is a reasonable methodology when a project is needed and placed into service during the projected test year, and the costs recognized during the

[70] Order No. PSC-09-0283-FOF-EI, issued Apr. 30, 2009, in Docket No. 080317-EI, *In re: Petition for rate increase by Tampa Electric Company*, pp 5–6.

projected test year will only represent a portion of the total annual costs a project will incur in subsequent periods. Therefore, it is reasonable to reflect the known and measurable change in an SYA so the company has the opportunity to recover the full investment. It is reasonable to annualize the cost of such projects (i.e., make an SYA) if such projects are needed and have certainty because they are to be placed in service during the projected test year. Of course, if a project is delayed or not constructed in the projected test year and an SYA was approved, the company would still receive revenues associated with the SYA without incurring the commensurate costs. This would potentially inflate a company's earnings. As such, we require that the company verify to this Commission that the asset(s) have been placed into service prior to the implementation of the SYA rate increase. TECO acknowledged as much at hearing and in its brief.

b. Evidences of Necessity for Projects Placed into Service After the Projected Test Year

The overarching consideration for an SYA project placed into service after the projected test year is the purpose and necessity of the asset to be implemented in the timeframe proposed by a company. The need for a project must be supported by evidence in the record. The necessity of an SYA project may be supported in different manners depending on a particular company's specific circumstances. Regardless, the company has the burden of offering evidence to support the need and necessity for an SYA project. Specifically, we shall consider whether the reasons to approve cost-recovery for the project in the current rate case outweigh the countervailing arguments and evidence including the inherent uncertainty in forecasting beyond a projected test year.

The need for a project can be supported by evidence showing the project will substantially improve safety or reliability, or solve an operational problem in a more efficient manner. For example, the need for a generating unit may be demonstrated when the evidence shows that the generating unit is necessary to maintain a minimum level of reliability or other reliability standards. On the other hand, an asset that is added for purely economic reasons, such as for reduced fuel costs, is inherently speculative by nature because fuel costs are not entirely predictable with definitive accuracy. Thus, whether projects will increase safety or reliability or further a significant operational efficiency, and not solely economic considerations, are important considerations for determining the necessity of any SYA projects.

Ultimately, TECO has the burden to prove, by a preponderance of the evidence, that the annualization or project(s) that underlie the SYA are necessary to be accounted for in the current rate case as opposed to a future rate case. In analyzing whether to approve an SYA project, we will consider whether the SYA project will substantially improve safety, reliability, or operational efficiency, as previously stated, and we will also consider whether the project will put pressure on the company's ability to earn within its range of return. In doing so, we may also consider whether it appears sufficiently likely that approval of the project will result in cost savings by avoiding or minimizing future rate proceedings. The individual components of TECO's requested SYAs in 2026 and 2027 are discussed in the following issues, Issues 95 through 102.

c. Evidence of Projected Savings Associated with the SYA

If the preponderance of the evidence demonstrates a need for an SYA, we should also consider the projected cost savings from the avoidance of future rate proceedings, whether from the elimination altogether or potential reduction in the scope of future proceedings, it should represent future cost savings that would benefit customers. If a company asserts that its ability to earn within its authorized range requires evaluation of additional revenues (customer growth) and cost savings, as well as expenses, in the subsequent period(s), we should consider the evidence the company puts forth on that.

The likelihood of cost avoidance from anticipated rate proceedings in the near future is a relevant consideration when evaluating whether to approve an SYA project. And the likelihood of cost avoidance should include an assessment of the accuracy of a company's forecasts as urged by OPC. However, the avoidance of a near future rate case expense is only one of the factors to consider, and there is no guarantee of the avoidance of a rate case in the near future as unforeseeable economic and other external factors may occur that are beyond the control of the Company.

3. Conclusion

We reviewed all of the parties' arguments and testimony as to SYA criteria for TECO. We find that annualization is a reasonable accounting methodolgy to reflect the known and measurable change in an SYA, so the company has the opportunity to recover the full investment. We also recognize that when a SYA project is placed into service after the projected test there, there is inherent uncertainty in forecasting beyond a projected test year. As such, the need for a project must be supported by evidence showing the project will substantially improve safety or reliability, or solve an operational problem in a manner more efficient than other alternatives. If the need is demonstrated by the evidecne, we should also consider the projected savings from avoiding or minimizing future rate case proceedings.

B. Proposed Solar Projects (Issue 95)

1. Analysis

In this docket, TECO is requesting full year revenue requirement values for the 2024 and 2025 Solar Projects, as well as an SYA for the 2026 Solar Projects.

a. Annualization of 2025 Solar Projects

Allowing an SYA for the incremental costs associated with the annualization of projects can be appropriate if the Company meets certain conditions for projects with an in-service date during the projected test year. We note that the 2025 Solar Projects have projected in-service dates prior to the end of the 2025 projected test year. Therefore, we find inclusion of the annualization associated with the 2025 Solar Projects in the 2026 SYA to be appropriate. However, after reviewing the Company's calculation of the 2026 SYA, it appears the associated

Accumulated Depreciation annualization of all the projects was omitted from the calculation of the incremental return on rate base. Therefore, there shall be an adjustment to include the corresponding Accumulated Depreciation annualization, as calculated in its breakdown of the 2025 projects.

b. New 2026 Solar Projects

TECO has proposed adding four future solar facilities by the end of 2026. The 2026 Solar Projects consist of the Big Four, Farmland, Brewster and Wimauma projects. These 2026 Solar Projects represent an addition of 242.2 MW of solar energy to TECO's system, with an in-service date of May 2026 for Big Four and December 2026 for the remaining units. Witness Aponte further testified that the 2026 Solar Projects have a projected installed costs of approximately $365.2 million.

Witness Aponte testified that the 2026 Solar Projects were cost-effective, which TECO determined by performing an analysis that compared the resource planning scenarios of the inclusion of the solar facilities and the omission of the solar facilities to determine the system CPVRR. The conclusion of the analyses determined that the addition of the 2026 Solar Projects would result in a CPVRR savings for customers of $78.7 million excluding emissions, primarily from system fuel savings of $385.6 million.

In our evaluation of the 2026 Solar Projects, we considered the need for the facilities. The need for additional physical plant can vary from a necessity for maintaining a minimum level of reliability (such as 20 percent planning reserve margin) or economic reasons (such as reduced fuel costs). Maintaining minimum reliability standards is paramount and not discretionary in terms of the timing of capital spending and subsequent recovery. In cross-examination, witness Aponte stated that the solar facilities provide no reserve margin benefit for winter peak which TECO uses for planning, and only a small percentage benefit for summer. Plant additions that are projected to reduce future fuel costs are more speculative and therefore provide utility management more discretion in terms of the timing of capital spending and recovery. By evaluating something further outside the projected test year, we note that the CPVRR analysis results are subject to greater uncertainty than compared to a forecast conducted closer to the in-service dates of the facilities. For example, during the hearing, witness Stryker agreed that although the revenue requirements would be recovered from customers starting in January 2026 there was no guarantee that the solar facilities would meet the scheduled in-service dates. The in-service dates for other units have already changed even during the current proceeding, such as the Bayside Energy Storage unit, delayed from an original April 2025 to December 2025 in-service date.

Because of the uncertainty of the factors that determine overall cost-effectiveness, especially fuel forecasts, determination on the cost-effectiveness of the 2026 Solar Projects would be more accurate closer to the in-service dates of the units. We note that in traditional ratemaking, TECO would be able to construct the units if existing rates would suffice or request a limited proceeding closer to the in-service date of the generating facilities. This would increase certainty in the forecasts and project completion while also better timing any rate increase associated with the cost of the facilities with the avoided system fuel benefits it produces.

Therefore, we find that the 2026 Solar Projects should not be included in the 2026 or 2027 SYA. This does not preclude TECO from filing a request for the cost recovery in a future proceeding.

No intervenor provided testimony specifically addressing this Issue. However, in its brief OPC argued that the projects should only be included if: the projects represent new capital investment, would cause TECO to earn below its earning range, and the Company can demonstrate a need for the projects. FIPUG adopted OPC's position on this Issue. FL Rising/LULAC and FRF argued that the projects should have a 35-year depreciation life. Our findings on depreciation life are reflected in Issue 7. No other parties provided positions on this issue.

2. Conclusion

The annualization associated with the 2025 proposed Solar Projects shall be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. But the proposed 2026 Solar Projects shall be removed and thus there will be no associated 2027 SYA.

C. Grid Reliability and Resilience Projects (Issue 96)

1. Analysis

As discussed in Issue 19, TECO requested full recovery of its GRR Projects in rate base. The GRR Projects consist of over 40 interdependent projects that include telecommunications, control center operational technology, back-office information technology, distributed energy resources and substations. TECO proposed to include 12 projects in rate base for the 2025 projected test year and to include two additional new projects as part of the 2026 and 2027 SYAs. While TECO witness Lukcic also identifies the Grid Communications Network projects as one of three new projects to be included in the 2026 SYA, this project has an in-service date of August 2025. Therefore, we have included that particular project as part of our analysis in Issue 19.

As previously stated, we find allowing an SYA for incremental costs associated with the annualization of projects can be appropriate if the Company meets certain conditions for projects with an in-service date during the projected test year. The GRR Projects identified and discussed in Issue 19 have projected in-service dates prior to the end of the 2025 projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, we find inclusion of the incremental cost associated with the annualization of the projects in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

a. New 2026 GRR Projects

TECO proposed two additional GRR projects that would be completed in 2026: (1) Customer Information Device Expansion; and (2) Grid Communications Network Hardware, Back Office IT Systems, and Control Systems.

The Customer Information Device Expansion project consists of reconstructing data models for lighting and non-meter devices, integration with existing systems, and revamping the business process for device billing. The projected costs for this project are $24.3 million in capital costs, with an in-service date of September 2026. The Grid Communication Network Hardware, Back Office IT Systems, and Control Systems project consists of Line Sensor Software, Private PLTE implementation, a WMS, and Distribution Planning Software Upgrades. The projected costs for this project are $120.6 million in capital costs, with an in-service date of December 2026. However, TECO adjusted its original proposal for this project by removing the Line Sensor Software and Distribution Planning Software Upgrades reducing the total amount by $12.3 million for a total of $108.3 in capital costs.

OPC maintained that the GRR Projects include the maintenance and replacement of obsolete equipment, which is normally included in the Company's annual budgets and would be accounted for in a representative test year Additionally, OPC witness Mara argued that the GRR projects should be planned for and deployed between rate cases or during a rate case's test year. OPC asserted that the GRR Projects are a continuation of various projects that TECO began planning and deploying before this rate case. OPC set forth its three criteria for SYAs and argued that the GRR Projects do not meet the criteria and should not be approved for the following reasons: (1) none of the GRR projects are generation-type; (2) TECO failed to demonstrate a need for the increase; and (3) TECO would be under no obligation to spend the revenues on these projects if approved by Commission.

Witness Mara testified that the GRR Projects in the SYAs have compounded the problem of the speculative nature of the costs and deployment timing of the GRR Projects since they are further out into future (i.e., the further out into the future, the less reliable the forecast). We agree with witness Mara and considered this argument while evaluating the need for the GRR Projects that are outside the 2025 projected test year. While the Customer Information Device Expansion Project and Grid Communication Network Hardware, Back Office IT Systems, and Control Systems Projects are reasonable, the costs are too speculative at this time given that the in-service dates are in 2026. Furthermore, our denial today does not preclude TECO from filing a request for cost recovery of these two new projects in a future proceeding.

As explained in Issues 14, 16, 17, and 19, FL Rising/LULAC's witness Rábago recommended that we should disapprove any capital spending project of $1,000,000 or more that is not supported by a comprehensive, objective, transparent, and documented BCA. In addition, witness Rábago recommended that we should disapprove most, if not all, of the rate recovery for the GRR Projects, as he believes that it is additional spending by TECO that is unjustified and unreasonable. As discussed in Issue 19, TECO witness Lukcic refuted these arguments. He testified that TECO believes that the SYA was the appropriate mechanism for the GRR Projects in order to help release pressure for going back into a rate case. To further support his argument, he testified that the projects are co-dependent and drive towards the most effective deployment of capital to maximize the benefits to customers and that the projects should be deployed in a certain order to maximize value for the customer. While there may be a need for these projects, these projects are too speculative at this time given that the in-service dates are in 2026. Based on the above, the Customer Information Device Expansion Project and the Grid Communications

Network Hardware, Back Office IT Systems, and Control Systems Projects shall not be included in the 2026 or 2027 SYA. Again, this does not preclude TECO from filing a request for the cost recovery in a future proceeding.

2. Conclusion

The Grid Communications Network Project has an in-service date of August 2025 and the annualization amount shall be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. However, the Customer Information Device Expansion Project ($24.3 million) and the Grid Communications Network Hardware, Back Office IT Systems, and Control Systems Projects ($108.3 million) are not anticipated to be completed until 2026. Having found their costs to be too speculative at this time, we therefore exclude them from the 2026 SYA and thus there shall be no corresponding 2027 SYA.

D. Polk 1 Flexibility Projects (Issue 97)

1. Analysis

As discussed in Issue 24, the Polk 1 Flexibility Project is the conversion of the existing Polk Unit 1, a 220 MW IGCC plant, to a 200 MW natural gas-fired simple cycle CT plant with an in-service date of May 2025. No intervenor other than OPC filed testimony on this Issue. In their briefs, FL Rising/LULAC, FEA, Sierra Club, and Fuel Retailers have taken no position on this Issue. OPC's position is to disallow 2026 SYA if its three conditions are not met. FIPUG, FRF and Walmart adopted OPC's position. As previously stated, allowing an SYA for the incremental costs associated with the annualization of projects can be appropriate if the Company meets certain conditions for projects with an in-service date during the projected test year. The Polk 1 Flexibility Project has a projected in-service date of May 2025. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, we find inclusion of the annualization associated with the Polk 1 Flexibility Project in the 2026 SYA to be appropriate, with an adjustment to include the annualization of the associated Accumulated Depreciation.

2. Conclusion

The annualization of TECO's proposed Polk 1 Flexibility project shall hereby be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

E. Energy Storage Projects (Issue 98)

1. Analysis

As previously discussed in Issue 20, TECO requested approval of the energy storage projects: Dover, Lake Mabel, Wimuama and Bayside.[71] Dover has a projected in-service date prior to the test year, in September 2024. The Lake Mabel, Wimuama, and Bayside projects all enter service during the projected test year, in January 2025, February 2025 and December 2025, respectively. In that issue, we approved inclusion of the projects in the 2025 projected test year. This Issue discusses the 2026 SYA associated with the four energy storage projects.

As previously stated, an SYA for the incremental costs associated with the annualization of projects that are in-service during the projected test year can be appropriate. As noted above, each of the four energy storage projects have an in-service date prior to the end of projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA.

In OPC's brief, OPC argued that the projects should only be included if the projects represent new capital investment, would cause TECO to earn below its earning range, and the Company can demonstrate a need for the projects. FIPUG adopted OPC's position on this Issue. FL Rising/LULAC and FRF argued that the projects should have a 20-year depreciation life. Our discussion on depreciation lives is located in Issue 7. No other party took a position on this Issue.

As discussed in Issue 65, we approved an adjustment to the ITC's related to the energy storage projects to reduce the 10-year amortization period proposed by TECO to a 5-year amortization period. In its original filing, TECO included an incremental annual ITC amortization amount of $1,196,669 to reflect the full in-service amounts for the energy storage projects. In TECO witness Strickland's revised rebuttal testimony, she provided a schedule listing the updated amounts for the battery storage ITCs in SYA 2026. The total amount of ITC's reported was $43,963,042. The annual amount of the 5-year ITC amortization in 2026 SYA is $8,792,608. The incremental amount of annual amortization of ITC's from 2025 is $2,165,796. Grossed-up for fees and taxes the amount is $2,910,050. The amount of the revenue requirement adjustment to reflect a 5-year amortization period as opposed to a 10-year amortization period is the difference between TECO's original incremental amount of $1,196,669 and our approved incremental amount of $2,910,050, which equates to $1,713,381.

2. Conclusion

Accordingly, the annualization associated with TECO's proposed Energy Storage Projects shall be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation. The Investment Tax Credits related to the battery storage projects in the 2026 SYA shall be adjusted to reflect a 5-year amortization period. The

[71] Formerly known as South Tampa Energy Storage Project.

annual ITC amortization shall be $8,792,608, which results in a revenue requirement decrease of $1,713,381 for the 2026 SYA.

F. Bearss Operation Center Project (Issue 99)

1. Analysis

As previously discussed, the BOC is a facility designed to withstand major hurricanes, protect all TECO's cyber assets, and operate TECO's command and control capabilities. The anticipated in-service date for the BOC is June 2025. TECO briefed that including the BOC in the 2026 SYA will mitigate the need for a successive general rate increase. Here we address the 2026 SYA associated with the BOC we approved in Issue 23.

As discussed in Issue 94, OPC has three criteria for inclusion of a project in an SYA. OPC briefed that the BOC meets the first criteria of a new and material capital investment; however, the BOC would not cause TECO to earn below its earning range. The remaining intervenors did not specifically address or take a position on this Issue.

As previously stated, we find allowing an SYA for incremental costs associated with the annualization of projects can be appropriate if the Company meets certain conditions for projects with an in-service date during the projected test year. The BOC's in-service date is June 2025, which is prior to the end of the projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Deprecation in its calculation of the 2026 SYA. Therefore, we find inclusion of the incremental cost associated with the annualization of the BOC in the 2026 SYA to be appropriate, with an adjustment to include the annualization of the associated Accumulated Depreciation.

2. Conclusion

TECO's proposed annualization of the Bearss Operations Center project shall be included in the 2026 SYA with an adjustment to include the annualization of the associated Accumulated Depreciation.

G. Corporate Headquarters Project (Issue 100)

1. Analysis

As discussed in Issue 21, we approved TECO's headquarters relocation on the basis of the CPVRR analysis results and the myriad of qualitative benefits the new location will provide. The anticipated in-service date for the new headquarters is June 2025. TECO briefed that including the new headquarters in the 2026 SYA will mitigate the need for a successive general rate increase. Here we address the 2026 SYA associated with TECO's Corporate Headquarters Project.

As discussed in Issue 94, OPC has three criteria for inclusion of a project in an SYA. OPC briefed that the new headquarters meets the first criteria of a new and material capital investment; however, the new headquarters would not cause TECO to earn below its earning range. The remaining intervenors did not specifically address or take a position on this Issue.

We allow an SYA for incremental costs associated with the annualization of projects that are in-service in the middle of the test year. The Corporate Headquarters' in-service date is June 2025, which is prior to the end of the projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Depreciation in its calculation of the 2026 SYA. Therefore, we find that the annualization associated with the Corporate Headquarters Project should be included in the 2026 SYA, with an adjustment to account for the annualization of the associated Accumulated Depreciation.

2. Conclusion

TECO's proposed annualization of the Corporate Headquarters Project shall be included in the 2026 SYA, with an adjustment to include the annualization of the associated Accumulated Depreciation.

H. South Tampa Resilience Project (Issue 101)

1. Analysis

The STR Project is a two-phase project consisting of two pairs of 18.5 MW RICE with in-service dates of December 2024 for Phase I and October 2025 for Phase II. As previously discussed in Issue 22, this project promotes energy grid reliability, provides operational benefits to customers, and is reasonable, prudent, and cost-effective.

As discussed in Issue 94, OPC has three criteria for inclusion of a project in an SYA. OPC argues the STR Project does not satisfy all of those criteria. It further alleges the STR Project is not prudent because there was a lack of federal government funding. FIPUG and Walmart adopted OPC's position. Meanwhile, FL Rising/LULAC argued against approving SYAs for 2026 and 2027 because the STR Project is not needed to meet reliability requirements. However, we addressed these arguments within our analysis of Issue 22.

We find allowing an SYA for incremental costs associated with the annualization of projects can be appropriate if the Company meets certain conditions for projects with an in-service date during the projected test year. Phase II of the STR Project has an in-service date of October 2025, which is prior to the end of the projected test year. However, as noted in Issue 95, the Company did not include the corresponding annualization of the Accumulated Deprecation in its calculation of the 2026 and 2027 SYAs. Therefore, we find inclusion of the incremental cost associated with the annualization of the STR Project in the 2026 and 2027 SYA to be appropriate, with an adjustment to include the annualization of the associated Accumulated Depreciation.

2. Conclusion

We therefore approve TECO's proposed annualization of the South Tampa Resilience Project in the 2026 and 2027 SYAs, with an adjustment to include the annualization of the associated Accumulated Depreciation.

I. Polk Fuel Diversity Project (Issue 102)

1. Analysis

TECO's Polk Fuel Diversity project involves adding fuel supply diversity to the generation at Polk Power Station by adding dual-fuel capability to three CTs at the site, allowing them to burn natural gas or fuel oil. According to TECO witness Aldazabal, two of the five CTs are already dual-fuel capable and the site already has fuel oil infrastructure that can serve the additional three units. Witness Aldazabal stated that this project helps to mitigate natural gas price spikes, fuel supply disruption risk, and energy demand in excess of natural gas supply and transportation capability. This project is estimated to cost approximately $53.9 million with an in-service date of December 31, 2026.

TECO has the burden to prove by a preponderance of the evidence that an SYA is needed or necessary to implement in the current proceeding. We also consider the likelihood of resulting savings from avoiding or minimizing future rate case proceedings. As noted above, the project has an in-service date of December 31, 2026, outside the 2025 projected test year.

The question is whether we should approve the inclusion the Polk Fuel Diversity Project in the 2026 and 2027 SYAs. OPC continues to advocate for its three criteria SYA analysis. FL Rising/LULAC witness Rábago and Sierra Club witness Glick recommended we deny this project because TECO has not demonstrated its cost-effectiveness. However, TECO witness Aldazabal explained that multiple options were reviewed for mitigating fuel supply disruption risks and we are persuaded by his testimony. For example, TECO considered several options to address risks associated with fuel supply limitations or disruptions, including liquid natural gas (LNG) storage, incremental firm gas transportation, solid fuel generation, purchased power, transmission, and renewable generation. Although witness Aldazabal indicated that the most viable options were LNG or oil, he explained that LNG's high capital expense, long-term O&M cost uncertainty, and permitting complexities coupled with potential community opposition made this option unattractive. Furthermore, alternative oil-based options such as adding oil pipelines or additional generation raised additional permitting and economic challenges. Ultimately, the evidence shows that adding dual-fuel capacity to the remaining three CTs was the most cost-effective option because TECO had pre-existing oil infrastructure. Additionally, when asked whether TECO could achieve the project's fuel diversity goal using clean energy instead, witness Aldazabal confidently responded that TECO could add oil fuel storage more cheaply than any clean energy alternative. We find TECO adequately explored alternatives before choosing the most viable, cost-effective option.

Moreover, we are persuaded by the testimony of TECO witness Aldazabal that the decision to invest in a backup oil project of this nature was needed to mitigate risk. Even with the growth in TECO's solar generation, TECO projects over 80 percent of its electricity for customers will come from natural gas fired generation. Florida's peninsular geography means that the state and TECO can face challenges importing fuel or power when one or more of the current sources is constrained or fully subscribed. Thus the surrounding interconnection options are limited by geography, making on-site fuel diversity even more important for TECO than for utilities with interconnection options all around them. The evidence and testimony presented to us demonstrates dual-fuel capability is necessary and prudent to mitigate operational risks related to fuel price spikes or primary fuel disruption from cyberattacks, terrorism, or natural disasters, like hurricanes. Based on the foregoing, we find TECO has established a need for the Polk Fuel Diversity Project and that this project constitutes a reasonable and prudent expense.

We also find it likely that granting these SYAs will minimize the likelihood of a future rate case. First, we have determined that the Polk Fuel Diversity Project is necessary, reasonable, and prudent. Second, the cost justifications provided by TECO witnesses Aldazabal and Chronister are reasonable and based upon reliable data. Therefore, approving the Polk Fuel Diversity Project in this proceeding will result in customer savings by minimizing the need for a future rate case.

2. Conclusion

In light of the foregoing findings and evidence, we grant a 2026 SYA for the Polk Fuel Diversity Project. We also grant a 2027 SYA for the annualization of this project, with an adjustment to include the annualization of the associated Accumulated Depreciation.

J. Rate of Return (Issue 103)

1. Analysis

This Issue is essentially uncontested wherein the parties contended that the overall rate of return for the 2026 and 2027 SYAs should reflect their respective positions and arguments for the projected 2025 test year overall rate of return in Issue 40. TECO proposed to use the overall rate of return approved by the Commission for the 2025 projected test year to calculate the 2026 and 2027 SYA. OPC seemed to agree because it refers to its argument in Issue 39 (the test year ROE issue) as its argument for this Issue. However, OPC's position statement describes its recommended overall rate of return based on investor sources (7.19 percent), not the overall rate of return OPC recommended for the WACC in Issue 40 (6.38 percent). FRF's position to use an overall rate of return of 6.38 percent for the 2026 and 2027 SYAs is the same as FRF's position to use OPC witness Woolridge's recommended overall rate of return in Issue 40. No other parties provided any specific argument on this Issue.

We approved an overall rate of return of 6.90 percent for the 2025 projected test year. Upon review of the testimony and exhibits in the record, there is not a compelling reason or argument to use a different overall rate of return for the 2026 or 2027 SYAs. Therefore, we find that flowing the overall rate of return of 6.90 percent from the project test year to the 2026 and 2027 SYAs is appropriate.

2. Conclusion

We approve an overall rate of return of 6.90 percent to calculate the 2026 and 2027 SYAs.

K. Customer Growth and Additional Revenues (Issue 104)

1. Analysis

This issue addresses whether the incremental revenues associated with an increase in TECO's customer base should be included in the Company's 2026 and 2027 SYAs.

While TECO argued that any revenue associated with customer growth should not be included in its requested 2026 and 2027 SYAs, OPC and other intervenors disagreed. OPC witness Kollen argued that, in the event this Commission grants any SYA, this Commission should reduce the requested 2026 and 2027 SYA revenue requirements and requested increases by OPC witness Dismukes' proposed adjustments. OPC argued that an adjustment to reflect an increase in base revenues due to both growth in TECO's customer base and an increase in forecasted sales should be considered. OPC believes that without these customer growth and sales considerations, TECO's 2026 and 2027 SYA requests are overstated. The proposed adjustments to SYA revenue by witness Dismukes are a reduction for the 2026 and 2027 SYAs of $7.994 million and $6.123 million, respectively. The other intervenors either adopted the position of OPC or took no position.

TECO argued that we should reject OPC's proposed adjustments for four reasons: (1) TECO witness Chronister stated that revenue from customer growth is "needed to cover costs associated with general rate base growth" and "the revenue requirements for the projects included in the Company's proposed SYA are needed to cover the costs of the major rate base additions included in the SYA;" (2) Inclusion of incremental revenues from customer growth would "moderate" the benefits of the SYA and may cause the need for additional rate relief for TECO in 2026 and/or 2027; (3) The Company contends that the inclusion of additional revenue from customer growth is "inconsistent with the method used to calculate the company's previous SoBRA and GBRA;" and (4) TECO witness Cifuentes argued that OPC witness Dismukes' methodology to project additional revenues is flawed.

We are persuaded by TECO's arguments that SYA adjustments for 2026 and 2027 should not reflect additional revenues generated from customer growth. We find that while the Company's revenues will gradually rise due to customer growth, so will the associated expenses that are incurred to provide service to those new customers. We further agree with TECO that this approach aligns with established precedent set forth by the Company's prior solar base rate adjustment (SoBRA) and GBRA proceedings which have not included such considerations of incremental revenues.[72]

Furthermore, we are persuaded that a revenue projection methodology which includes additional revenues from customer growth without a thorough analysis of corresponding additional expenses in 2026 and 2027 creates an incomplete, and potentially skewed, financial composition of the Company. Therefore, we find it inappropriate in this circumstance to account for increased revenues alone. Lastly, we agree with TECO that the inclusion of additional customer growth revenue as a credit against TECO's SYAs could possibly reduce the intended effects of the SYAs.

By maintaining consistency with past treatment of SYAs and ensuring that all relevant financial factors are considered, the SYA for 2026 and 2027 should not reflect additional revenues due to customer growth.

2. Conclusion

The SYAs for 2026 and 2027 shall not reflect additional revenues resulting from customer growth for the reasons stated. Therefore no adjustments will be made.

L. Incremental Operating and Maintenance Expense (Issue 105)

1. Analysis

TECO requested $6.8 million in incremental O&M expenses for the 2026 SYA and $4.8 million in incremental O&M expenses for the 2027 SYA. TECO briefed that the incremental O&M expenses should be included in the SYAs and that the expenses are consistent with the method used to calculate the revenue requirement for prior GBRAs and SoBRAs. However, OPC briefed that the incremental O&M expenses should be excluded from the SYAs due to TECO's failure to reflect the O&M expense savings from TECO's cost-effectiveness determinations. The remaining intervenors did not specifically address this issue.

As addressed in Issues 95 and 96, we approved adjustments to the Solar Projects and GRR Projects. These adjustments result in a total reduction of $4.0 million for the 2026 SYA and $4.6 million for the 2027 SYA O&M expenses. This results in incremental O&M expenses of $2.9 million for the 2026 SYA and $186,000 for the 2027 SYA.

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[72] Order PSC-2020-0448-TRF-EI, issued November 20, 2020, in Docket 20200064-EI, *In re: Petition for a limited proceeding to approve fourth [solar base rate adjustment] SoBRA, by Tampa Electric Company;* Order PSC-2023-0348-TRF-EI, issued November 17, 2023, in Docket 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.*

2. Conclusion

We therefore approve amounts of incremental O&M expenses of $2.9 million for the 2026 SYA and $186,000 for the 2027 SYA.

M. Depreciation Rates and Investment Tax Credits Amortization (Issue 106)

1. Analysis

Having granted SYAs, the depreciation expense used to calculate the 2026 and 2027 SYA must be adjusted to reflect our decision on depreciation rates for the 2025 test year in accordance with Rule 25-6.0436(4)(f), F.A.C. This rule prescribes that upon Commission approval by final order establishing an effective date, the utility shall reflect on its books and records the implementation of the depreciation rates approved by the Commission.

For the ITC amortization, this Issue is a fall-out. None of the parties proposed an adjustment to the ITC amortization approved for the 2025 projected test year. TECO argued the ITC amortization should be based on the depreciable lives of the assets giving rise to the ITCs as reflected in its positions on Issues 10 and 65. OPC agreed that whatever adjustments we approve should be reflected in the 2026 and 2027 SYA. All the other parties either had no position or adopted the position of OPC.

As discussed in Issues 10, 65, and 98, we ordered that the amortization of ITCs be revised to match the depreciation lives of the related property, except for the ITCs related to TECO's battery storage assets. In Issue 65, we changed the amortization period for the battery storage assets from 10-years to 5-years for the 2025 projected test year, which is a shorter period than the depreciation life. Therefore, the ITC amortization period for the battery storage assets will be set at 5 years for the 2026 SYA. All other ITC amortization periods will match the depreciation lives for the related property as discussed in Issue 10.

2. Conclusion

Therefore, the depreciation expense and Investment Tax Credits amortization used to calculate the proposed 2026 and 2027 SYA shall be adjusted to reflect our decisions on depreciation rates and ITC Amortization in the 2025 projected test year. In addition, the ITC amortization period for the battery storage assets shall be set at 5 years for the 2026 SYA. All other ITC amortization periods shall match the depreciation lives for the related property as discussed in Issue 10.

N. Incremental Revenues (Issue 107)

1. Analysis

This is a fall-out Issue. TECO witness Chronister provided a calculation of the 2026 and 2027 SYAs. TECO requested the recovery of incremental revenues in the amount of

$100,074,841 and $71,847,925 through its proposed 2026 and 2027 SYA, respectively. The Company's proposed incremental revenues for each year are the sum of the return on rate base and incremental operating expenses associated with each project reflected in 2026 and 2027.

In Issues 94 through 102, we approved a 2026 SYA reflecting the incremental annualization of projects that went in service in 2025: Polk 1 Flexibility, Energy Storage, South Tampa Resilience, Corporate Headquarters, and the Bearss Operation Center, along with components of the proposed GRR Projects and solar projects. We also approved a 2026 SYA for the Polk Fuel Diversity project. As such, the return on rate base for the 2026 and 2027 SYA was adjusted to reflect our decisions in those issues, along with the rate of return of 6.90 percent from Issue 103 and the updated NOI multiplier recommended in Issue 68. Likewise, the incremental operating expenses were also adjusted to reflect the amounts associated with annualization in 2026 and 2027. In total, the 2026 SYA should be decreased by $13,447,046, for a total annual amount of $86,627,795. Our total adjustments and final approved costs for the 2026 SYA are reflected in Table 18.

Table 18
2026 SYA

Project	Original Request	Commission Adj.	Final Approved
Polk 1 Flexibility	$5,185,793	($483,280)	$4,702,513
Energy Storage	$8,990,287	($3,320,539)	$5,669,748
Corporate HQ	$10,787,343	($714,214)	$10,073,129
Bearss Operation Center	$27,025, 746	($1,730,660)	$25,295,086
South Tampa Resilience	$9,963,097	($654,940)	$9,308,157
Polk Fuel Diversity	$2,137,872	($151,376)	$1,986,496
GRR	$4,599,348	($2,069,015)	$2,530,333
Solar	$31,385,355	($4,323,022)	$27,062,333
Total	$100,074,841	($13,447,046)	$86,627,795

In Issues 101 and 102, we approved SYAs to reflect the annualization of projects placed into service in a period prior to the proposed SYA. Our total adjustments and final approved costs for the 2027 SYA are reflected in Table 19.

Table 19
2027 SYA

Project	Original Request	Commission Adj.	Final Approved
South Tampa Resilience	$3,921,376	($496,173)	$3,425,203
Polk Fuel Diversity	$6,057,369	($393,226)	$5,664,143
GRR	$28,788,393	($28,788,393)	$0
Solar	$33,080,787	($33,080,787)	$0
Total	$71,847,925	($62,758,579)	$9,089,346

2. Conclusion

Therefore the annual amount of incremental revenues we approve for recovery through the 2026 SYA is $86,627,795, which is for recovery of 2026 projects and annualization associated with projects added in 2025 only. We also approve for recovery through the 2027 SYA the annual amount of incremental revenue of $9,089,346, which is for annualization of projects added in 2026.

O. Rate Design (Issue 108)

1. Analysis

TECO provided its 2026 and 2027 subsequent years rate calculations in Exhibit 15. This Exhibit also includes an explanation of TECO's proposed rates for 2026 and 2027. TECO proposed applying its proposed 2026 and 2027 SYA amounts pro rata to customer, energy, and demand charges for its non-lighting classes. Under TECO's proposed SYA amounts, the percent increase to rates for 2026 is 5.9407 percent and 4.0180 percent for 2027. Although we note that the final SYA adjustments depend on the SYA amounts granted and the cost of service approved. TECO stated that it did not apply SYA revenues to its lighting classes to continue to move the lightings rate classes to parity in 2026 and 2027. We find that in MFR Schedule E-8 that the lighting class is above parity.

2. Conclusion

TECO's proposed rate design to develop customer rates for the 2026 and 2027 SYA is reasonable. The rate calculation should reflect our approved cost of service and the SYA costs approved herein.

P. Effective Date (Issue 109)

1. Analysis

This Issue appears uncontested. TECO witness Chronister's testimony and exhibits indicate that both the 2026 and 2027 SYAs should be implemented on the first billing cycle of each respective year. FRF and Walmart agreed. OPC witness Kollen appears to agree as well because he testified that the first SYA should take place on January 1, 2026, and the second SYA should take place on or about January 1, 2027. FL Rising/LULAC argued that if this Commission approved an SYA, it should become effective on January 1 of its respective year.

FIPUG stated in its brief that the SYA should be applied as equal percentage increases in the demand and energy charges. However, these arguments are not germane to this Issue and were addressed by us elsewhere. No other party took a position on this Issue.

2. Conclusion

Therefore, our approved 2026 SYA shall become effective with the first billing cycle in January 2026. Our approved 2027 SYA shall become effective with the first billing cycle in January 2027. TECO shall govern itself accordingly, consistent with our other rulings in this Order.

Q. Rates (Issue 110)

1. Analysis and Conclusion

TECO's filing its proposed 2026 and 2027 SYA rates for Commission approval the September before 2026 and 2027, respectively, while reflecting then current billing determinants, ensures that SYA rates will be based on the most recent available information. OPC, FL Rising/LULAC, FRF, and Walmart agreed that TECO should be required to file its proposed 2026 and 2027 SYA rates for Commission approval.

There being no dispute that we must consider and approve these rates before they go into effect, TECO shall file its proposed 2026 and 2027 SYA rates for approval in September 2025 and 2026, respectively, verifying the in-service dates of all projects and using then current billing determinants.

XI. Other

A. Corporate Income Tax (Issue 111)

As part of its Petition, TECO requested a corporate income tax change provision similar to the method presented in Section 11 in the 2021 Settlement Agreement.[73] However, TECO has not accounted for, or included, any potential tax law changes in the instant Petition. TECO argued that the 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. In its brief, TECO recognized the ambiguity of the term "normalization" in Section 11 of the 2021 Settlement Agreement that gave rise to Issue 64 in this docket. Consequently, TECO proposed to modify the language of the tax law provision reflected in paragraph 11(c)(iv) prospectively such that normalization will be required for new tax credits if, and only if, required by the Internal Revenue Code or related tax regulations. TECO further argued that although provisions like the Company's proposed tax change mechanism have only been approved by this Commission as part of settlement agreements, this does not mean we lack jurisdiction to approve the proposed mechanism in this proceeding.

OPC argued that we should not approve the corporate income tax change provision in this rate case, claiming it would constitute reversible error. The corporate tax change provision in

[73] Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20210034-EI, *In re: Petition for rate increase by Tampa Electric Company.*

Section 11 of the 2021 Settlement Agreement describes the effects on income tax expense, including the amortization of deficient or excess- deferred income taxes, both protected and unprotected, accumulated deferred income taxes, and tax credits resulting from changes in income tax rates and the modification of existing tax credits and new tax credits. OPC witness Kollen contended that the effects of any potential corporate income tax change can be addressed by this Commission on its own motion, on a statewide basis, or through a petition filed by TECO on its own initiative if and when some such corporate income tax changes are enacted. OPC witness Kollen further testified there was no need in this proceeding to attempt to preemptively prescribe future Company petitions or calculation methodologies in such filings, which may be considered to have presumptive validity.

OPC argued that this Commission has established a policy that a rate case is not the proper venue for establishing prospective changes in rates as a result of a future change in federal income taxes.[74] We agree. This Commission previously rejected proposals for similar tax change law provisions in Docket Nos. 20220067-GU and 20220069-GU. In Order No. PSC-2023-0103-FOF-GU, we denied Florida Public Utilities Company's (FPUC) request and concluded, "If there is a change in State or Federal tax laws FPUC or OPC has the opportunity to file a petition for a limited proceeding pursuant to Section 366.076, F.S., requesting that we consider the issues and expenses affected by a potential corporate tax law change."[75] Additionally, in Order No. PSC-2023-0177-FOF-GU, we found that:

> . . . a tax law change provision in this case is unnecessary because there is no evidence supporting a need for it. Should there be a tax law that comes into effect that will affect the rates set forth in this order, a limited proceeding pursuant to Section 366.076, F.S., is available for FCG or OPC to address any potential future State or Federal income tax law changes, which would provide an opportunity to consider all of the issues arising from such tax law changes and to establish the appropriate rates at that time.[76]

The status of potential tax law changes in the instant case is no different than the two previously cited natural gas rate cases. That is, there is no evidence in the record that any state or federal tax law changes are pending, and TECO did not provide any evidence the tax law change provision is necessary and would benefit customers. In fact, TECO did not implement the tax law changes related to PTCs as a result of the IRA as described in the 2021 Settlement Agreement from its prior rate case, and deferred disposition of the PTC benefits to this proceeding, which we addressed in Issue 64. Accordingly, the most appropriate process to address any potential future state or federal income tax law change is through a limited proceeding or rate case to allow us and interested parties the opportunity to address all the issues

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[74] Order No. PSC-2023-0103-FOF-GU, issued March 15, 2023, in Docket No. 20220067-GU, *In re: Petition for rate increase by Florida Public Utilities Company, Florida Division of Chesapeake Utilities Corporation, Florida Public Utilities Company – Ft. Meade, and Florida Public Utilities Company – Indiantown Division.*
[75] *Id.*
[76] Order No. PSC-2023-0177-FOF-GU, issued June 9, 2023, in Docket No. 20220069-GU, *In re: Petition for rate increase by Florida City Gas.*

that may arise therefrom and set the appropriate rates at that time. We find a provision for a potential corporate income tax law change is not necessary.

2. Conclusion

If there is a change in state or federal tax laws, TECO or other intervenors have the opportunity to file a petition for a limited proceeding pursuant to Section 366.076, F.S., requesting that this Commission consider the issues and expenses affected by a potential corporate tax law change. Therefore, we deny TECO's request for a corporate income tax change provision as detailed above on the bases of it being too speculative and unnecessary.

B. Storm Cost Recovery (Issue 112)

1. Analysis and Conclusion

TECO requested to continue its Storm Cost Recovery Provision, consistent with its 2021 Agreement, approved by Order No. PSC-2021-0423-S-EI. The agreement states that TECO may seek recovery of costs associated with any tropical systems named by the National Hurricane Center. Specifically, the recovery of storm costs will begin, on an interim basis (subject to refund) sixty days following the filing of TECO's petition for storm cost recovery. The storm cost recovery charge will be based on a 12-month recovery period if the storm costs do not exceed $4.00/1,000 kWh and will be a monthly charge. If the cost exceeds $4.00/1,000 kWh, the costs shall be recovered in subsequent years as determined by this Commission. All storm costs will be calculated pursuant to Rule 25-6.0143, F.A.C. The costs shall be limited to the following: (1) costs resulting from such tropical system named by the National Hurricane Center; (2) the estimate of incremental storm restoration costs above the level of the storm reserve prior to the storm; and (3) the replenishment of the storm reserve to $55,860,642.

TECO witness Chronister explained that TECO will adhere to our storm cost recovery rules that assure the amount TECO wants to collect through the surcharge does not include any expenses that are already being recovered in base rates. Witness Chronister testified that TECO would still petition the Commission for recovery of the amount of restoration costs. In addition, witness Chronister agreed that for its true-up, TECO would refund any over collected storm costs to customers the same way those costs were originally collected. TECO would flow the over-collected amount through the ECCR to be part of that factor thereby avoiding a separate docket for the true-up amount. TECO further argued, and we agree, that just because a mechanism was approved by this Commission through a settlement agreement does not mean we are without jurisdiction to approve such a mechanism outside of a settlement agreement.

Walmart and FRF expressed concern, in their briefs, regarding the cost allocation and rate design associated with storm cost recovery and maintain that this issue should not be addressed through a rate case proceeding. However, neither party filed testimony specific to this issue. Walmart briefed that TECO should not recover storm costs from demand-metered customer via energy charges. Walmart also argued the storm cost recovery rate design was not squarely presented to us in this rate case. Walmart asserted that even though TECO witness

Williams admitted that TECO would collect storm costs from demand-metered customers via demand charges, witness Williams did not have an understanding of TECO's plan for future storm cost collection on a going forward basis.

Walmart requested that if this Commission decides that storm cost recovery rate design is not an issue in this case, that we state that it is an issue for TECO's next storm cost recovery docket. TECO responded to Walmart's concerns by stating that customers will be refunded the same way the storm costs were collected, and that the rate design of the storm costs should be addressed in TECO's next storm cost recovery docket. We find that this Issue addresses the overall methodology as to how TECO will seek recovery of incurred storm costs and what costs are appropriate for recovery. TECO will still petition us for recovery of the restoration costs, at which time Walmart can address this Commission regarding rate design.

OPC argued that we should deny the Storm Cost Recovery Mechanism. In addition to renewing here the objections it raised in Issue 111, OPC stated that the elements of the Storm Cost Recovery Mechanism are available to TECO and the Commission by operation of law and can be implemented regardless of the provisions of the 2021 Settlement Agreement. OPC further argued that the various threshold or numeric values in the provision were negotiated and have no basis in evidence or law. OPC points out that Paragraph 8(d) of the 2021 Settlement Agreement says that the Storm Cost Recovery Mechanism expires when the rates are set in this case. Furthermore, OPC argued that TECO's approach does not provide this Commission with an alternative record that is supported by evidence to implement it.

We agree with OPC that the Storm Cost Recovery Mechanism can be implemented regardless of the provisions of the 2021 Agreement as we have jurisdiction to approve a Storm Cost Recovery Mechanism. We find based on the testimony and evidence presented that the mechanism has worked well in the past, not because it originated from a settlement but because the process allows for timely recovery of storm restoration costs subject to Commission review, party intervention, and a true-up process that protects ratepayers.[77] Furthermore, none of the intervenors argued to change specific aspects of the Provision or put forth evidence supporting which aspects should be revised. It should also be noted that in its Prehearing Statement, OPC believed this Provision should be approved as long as it allowed for a tariff filed by the Company to become effective subject to a hearing. However, OPC then amended its position in its brief to recommend that this Provision should not be approved for the reasons discussed above.

The 2021 Settlement Agreement specified that TECO's Storm Cost Recovery Provision would remain in effect until its base rates were reset by this Commission. As the instant docket is the subsequent base rate proceeding to the 2021 Settlement Agreement, we find this issue is appropriate to include here. We further find that continuation of TECO's Storm Cost Recovery Mechanism should be continued as it has worked well for many years. In addition, this Provision is an appropriate way for the Company to recover costs in a timely manner subject to scrutiny by

[77] See Docket No. 20230019-EI, *In re: Petition for recovery of costs associated with named tropical systems during the 2018-2022 hurricane seasons and replenishment of storm reserve, by Tampa Electric Company*.

this Commission and intervening parties, thereby ensuring ratepayers are protected. Based on the foregoing, we approve the Storm Cost Recovery Provision.

C. Asset Optimization Mechanism (Issue 113)

1. Analysis

a. History of the Asset Optimization Mechanism

In 1984, this Commission established a shareholder incentive program to encourage all investor-owned utilities (IOUs) to make economy energy sales.[78] This shareholder incentive program established that revenues for economy sales were moved from base rates to the Fuel and Purchased Power Cost Recovery Clause and allowed the IOUs to retain 20 percent of the gains on the sales. This Commission stated that the intended purpose of the shareholder incentive program was to encourage IOUs to use their excess capacity to make economy sales and eliminate the potential for over-recovery or under-recovery of revenues associated with economy energy sales.

In 2000, this Commission modified the shareholder incentive program for all IOUs that applied to gains from certain economic wholesale power sales.[79] The shareholder incentive program established that a three-year moving average of gains to be an appropriate threshold and that all gains below that threshold would be credited to ratepayers and all gains above that threshold to be split 80 percent to 20 percent between ratepayers and shareholders, respectively.[80] As stated in the order approving the incentive mechanism, we found that this incentive structure "minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring."[81] This structure also maintained that ratepayers would receive 100 percent of the gains from wholesale purchases and any gains generated from the use of other ratepayer-supported assets.

In 2012, this Commission approved a settlement for FPL which established FPL's Asset Optimization Mechanism (AOM) as a four-year pilot that was designed to allow FPL to share gains created through electric wholesale purchases, wholesale sales, and asset optimization.[82] Then in 2016, this Commission approved a second FPL settlement that continued FPL's AOM with modifications that increased the sharing thresholds and recovery for variable O&M associated with economy sales.[83] In 2021, FPL's 2021 Settlement Agreement modified the company's previously approved AOM to apply to all fuel sources, allow the monetization of

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[78] Order No. 12923-PAA-EU, issued January 24, 1984, in Docket No. 19830001-EU-B, *In re: Fuel Adjustment Recovery Clauses of electric utilities – treatment of gain on economy sales.*
[79] Order No. PSC-00-1744-PAA-EI, issued September 26, 2000, in Docket No. 19991779-EI, *In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities.*
[80] *Id.* at 10.
[81] *Id.* at 11.
[82] Order No. PSC-13-0023-S-EI, issued January 14, 2013, in Docket No. 20120015-EI, *In re: Petition for increase in rates by Florida Power & Light Company.*
[83] Order No. PSC-16-0560-AS-EI, issued December 15, 2016, in Docket No. 20160021-EI, *In re: Petition for rate increase by Florida Power & Light Company.*

RECs, and increase the sharing thresholds.[84] Per the 2021 Settlement Agreement, FPL's current AOM has been approved as a program by us with no expiration date.

In 2016, TECO requested a pilot incentive mechanism, the Optimization Mechanism, which would allow the Company to make gains on wholesale sales, wholesale purchases and include asset optimization activities. Following this in 2017, we approved a settlement agreement for TECO (2017 Settlement) which established TECO's pilot AOM for a four year period beginning in January 2018.[85] The 2017 Settlement adopted TECO's proposed AOM which allowed the Company to receive gains from engaging in wholesale sales, wholesale purchases and optimization activities. Optimization activities include, but are not limited to: (1) gas storage utilization; (2) delivered gas sales; (3) gas production area sales; (4) gas transportation sales; (5) outsourcing of optimization functions; and (6) coal transportation savings. These activities did not include sales of renewable energy credits (RECs), which the 2017 Settlement established were retained for customers and 100 percent of net gains flowed back to customers through the ECRC.

The 2017 Settlement AOM shared net gains on eligible activities based upon the total amount of gains through a series of sharing thresholds that each had a different allocation of the net gains. Customers would receive the benefit of 100 percent of the first $4.5 million in net gains, only 40 percent of the net gains between $4.5 million and $8 million, and just 50 percent of net gains in excess of $8 million. The remaining net gains flowed to TECO shareholders. We note that this differs from TECO's original Optimization Mechanism proposal, which had an initial $3.5 million threshold which represented the savings TECO achieved from wholesale power purchase savings and power sales over the prior four years, rounded up to the nearest half million dollar amount, then establishing the second threshold point at double this value. The 2017 Settlement AOM increased each of these values by $1 million.

In 2021, this Commission extended TECO's AOM when it approved TECO's 2021 Settlement Agreement with a revised expiration date of December 31, 2024.[86] The 2021 Settlement did not alter the previously established savings thresholds or allocated percentage of gains, but did clarify that two activities were not included in the eligible asset optimization activities: release of natural gas pipeline capacity and retirement/release of railcars.[87] Gains from those two activities were to be returned 100 percent to ratepayers. The 2021 Settlement also reiterated that the full benefits of RECs associated with the future solar projects subject to the settlement would be retained for customers and 100 percent of net gains flowed back to customers through the ECRC. Between 2018 and 2023, TECO's existing AOM has generated a

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[84] Order No. PSC-2021-0446-S-EI, issued December 2, 2021, in Docket No. 20210015-EI, *In re: Petition for rate increase by Florida Power & Light Company.*
[85] Order No. PSC-2017-0456-S-EI, issued November 27, 2017, in Docket No. 20170210-EI, *In re: Petition for limited proceeding to approve 2017 amended and restated stipulation and settlement agreement, by Tampa Electric Company.*
[86] Order No. PSC-2021-0423-S-EI, issued November 10, 2021, in Docket No. 20200264-EI, *In re: Petition for approval of 2020 depreciation and dismantlement study and capital recovery schedules, by Tampa Electric Company.*
[87] *Id.*

total of $67.5 million in gains, with $45.6 million of the total benefits allocated directly to ratepayers.

b. TECO Rate Case Petition

In this docket, TECO is requesting to: (1) extend the established AOM beyond the December 2024 expiration date; (2) modify the allowable optimization activities to include the release of natural gas pipeline capacity and the sale of RECs, and (3) maintain the existing sharing thresholds and allocation percentages. The dispute revolves around whether it is appropriate to do so.

c. Extension of Asset Optimization Mechanism

The structure of any shareholder incentive program is intended to allow ratepayers to continue to receive benefits that were generated from the IOU's activities using ratepayer supported assets and reward the IOUs for performing better than they performed previously, while minimizing the possibility of IOUs being rewarded for behavior that was already occurring. During cross examination, FIPUG questioned TECO witness Heisey if the benefits accrued from AOM activities would continue regardless of the AOM being adopted. In response, witness Heisey stated that the benefits produced by the optimization activities in the AOM would continue without the approval of AOM, but TECO could not guarantee the same level of benefits would be generated absent the program. Although this Commission has not made a previous judgement on the appropriateness of the AOM revenue-sharing thresholds or percentages, TECO's existing AOM has generated savings for TECO ratepayers. We find that there is a value to mechanisms that incentivize companies to seek additional activities to produce savings for ratepayers. As such, we shall approve that TECO's proposed AOM be extended beyond its December 2024 expiration date, with an effective date of January 1, 2025. This will allow the AOM to continue in its current form until the program is terminated or subsequently modified by this Commission. As detailed below, we do not approve of adding additional covered activities when the current sharing thresholds are being maintained.

d. Additional Eligible Activities

Regarding the release of natural gas pipeline capacity, TECO witness Heisey testified that the gains would be generated for customers through the AOM by selling excess natural gas pipeline capacity not needed for TECO's native load. Currently, net gains from the release of natural gas pipeline capacity return 100 percent to ratepayers. However, the witness testified that value of capacity release is currently uncertain, and TECO projects the annual gains from these activities to be between $0 and $2 million. Witness Heisey went on to testify that value of capacity release is currently uncertain and that when capacity release was previously included in TECO's AOM from 2018 to 2021, the Company was not in a position to release capacity or the value of capacity release did not provide benefits to customers. We note that the release of natural gas pipeline capacity is an activity the Company can currently engage in that would provide 100 percent benefits towards ratepayers.

Regarding REC sales, witness Heisey testified that only RECs not needed for TECO's retail program would be sold and the Company would not engage in forward REC sales. Currently, net gains from the release of REC sales return 100 percent to ratepayers through the ECRC. The witness further testified that the proposed inclusion of the revenues associated with REC sales would flow to customers as gains through the AOM, which would lower ratepayer fuel expenses. However, witness Heisey testified that in 2023 TECO began to engage in sales of RECs on the voluntary market and per the terms of the 2021 Settlement all revenues generated from REC sales are returned to customers through the ECRC. The witness further testified that the value of RECs in the voluntary market were low and were expected to experience continued downward pressure.

Although capacity release of gas pipeline was included in TECO's AOM previously, TECO did not engage in the activity due to market conditions and has not provided evidence in the record to indicate that these market conditions have changed. Nothing prohibits TECO from engaging in capacity release and if market conditions did improve, the inclusion of capacity release as an allowable optimization activity would reduce the amount that ratepayers would benefit. Similarly, TECO currently engages in REC sales, with all revenues being returned to ratepayers. The inclusion of REC sales in the AOM would reduce the value of benefits associated with REC sales that TECO ratepayers would otherwise receive. Therefore we find that TECO's proposed additions of releasing natural gas pipeline capacity and REC sales as allowable optimization activities lack enough supporting evidence in the record and would not be to the benefit of ratepayers. Therefore, we deny the requested expansion of AOM eligible activities.

e. Maintaining Asset Optimization Mechanism Sharing Thresholds and Percentages

As previously discussed, TECO's 2017 Settlement AOM initial customer sharing threshold was established using a historic four-year average plus a $1 million adder, while the second threshold was set at double the initial savings, with no changes in the 2021 Settlement AOM. In this proceeding, TECO proposed to continue its existing 2021 Settlement negotiated initial $4.5 million and second $8.0 million sharing thresholds with the additional allowable optimization activities. We note that no intervening parties provided testimony in regards to TECO's proposed AOM. In response to interrogatories, TECO asserted that it was not opposed to changing the sharing thresholds or percentages as long as an appropriate incentive mechanism exists for the Company. However, we conclude that it would be improper to add more revenue generating activities into the AOM without a corresponding increase to the sharing thresholds for the ratepayers and Company, alike. Therefore, we find TECO's currently established $4.5 million and $8.0 million sharing thresholds shall be maintained as is.

f. Generic Proceeding

We recognize the dissonance between the various AOMs for each IOU. Similar to the Commission-approved shareholder incentive program from 2000, the asset optimization activities the IOUs are engaging in apply to all electric IOUs. In response to an interrogatory, TECO stated that it believed that a separate docket to address the continuation of the AOM would be appropriate. Therefore, we will establish a generic proceeding which will allow this

Commission to both consolidate the various AOMs and equally establish the allowable optimization activities and revenue-sharing thresholds for all IOUs. A staff workshop will be the first step in this process to allow IOUs and interested parties to provide input for an all-encompassing AOM.

No party provided testimony regarding this Issue, however in its brief OPC maintained that the program should not be authorized because it is improper to use a settlement agreement as precedent for the program. OPC further argued that no AOM has been authorized by this Commission as all AOM's are products of settlements. OPC maintained that there was no established procedure for determining sharing thresholds for the AOM. FEA and Fuel Retailers took no position on this Issue with all other intervenors adopting OPC's position.

Our jurisdiction and authority for electric rate cases, however, rests in Chapter 366, F.S., whether in approving a settlement agreement or ordering rates after a full hearing. The mere existence of a settlement agreement does not permit this Commission to grant something it otherwise could not, absent the settlement agreement. As discussed above, we found that there is a value to mechanisms that incentivize companies to seek additional activities to produce savings for ratepayers. We allow the AOM continue not merely because it was part of the 2021 Settlement Agreement. Rather, it is the benefits that TECO's customers have derived over the past six years (over $45 million dollars) that warrants continuation of the AOM at this time. Allowing the AOM to continue in its current form until the program is terminated or modified by us, in a future proceeding, benefits TECO's ratepayers. OPC's arguments lend further support to our decision to implement a generic proceeding regarding a broadly applied AOM.

2. Conclusion

Based on the foregoing, the proposed AOM shall be approved, effective January 1, 2025, with modifications. As the customer-sharing threshold has not been increased, the requested REC sales and natural gas sales should not be added to the allowable optimization activities. In addition, a new docket shall be established for a generic proceeding to address allowable optimization activities and revenue-sharing incentives for all investor-owned utilities.

D. Clean Energy Transition Mechanism (Issue 114)

1. Analysis and Conclusion

TECO witness Sizemore addressed the Clean Energy Transition Mechanism (CETM) factors in her direct testimony. Witness Sizemore explained that per the 2021 Settlement Agreement, TECO removed the costs associated with the undepreciated net book value of retired Automatic Meter Reading assets, the undepreciated net book value of Big Bend Units 1 through 3, and the dismantlement reserve deficiency associated with Big Bend Units 1 through 3. The 2021 Settlement Agreement specifies that recovery of these costs will be over 15 years through a separate charge on customers' bills.

Per the 2021 Settlement Agreement, TECO is required to modify the CETM factors every three years and complete a final true-up at the end of the 15-year period. Witness Sizemore explained that the 2021 Settlement Agreement specifically requires that TECO adjust the CETM factors to reflect changes to TECO's overall rate of return each time TECO's midpoint ROE is reset.

TECO proposed revised CETM factors for the period beginning in January 2025 which reflect TECO's requested ROE of 11.5 percent. Witness Sizemore further explained that the CETM factors were developed based on the cost of service study utilized in the 2021 rate case. Meanwhile, FL Rising/LULAC took the position that the CETM factors should be discontinued, but at the very least, should be allocated based on FL Rising/LULAC's proposed cost of service. But we are aware that the CETM factors were approved by us in the 2021 Settlement Agreement and there is no record evidence to support discontinuation of these factors. Therefore, we reject FL Rising/LULAC's argument on this issue.

The CETM factors were originally approved by this Commission in the 2021 Settlement Agreement. However, by the terms of that settlement agreement, the CETM factors must be adjusted to reflect changes to overall rate of return each time TECO's midpoint ROE is reset. Our earlier decisions on ROE and cost of service directly impact this Issue, necessitating adjustments to TECO's initial proposal. Specifically, we changed TECO's mid-point ROE to 10.5% and ruled differently on some cost of service issues. Our newly approved CETM factors and associated tariffs (Fifth Revised Tariff Sheet No. 6.025) are reflected in Attachment F and are hereby approved.

E. Senior Care Program (Issue 115)

1. Analysis

The proposed Senior Care Program offers a fixed $10 monthly bill credit to TECO's low-income customers 65 and older. TECO witness Williams stated that to qualify for the Senior Care Program, a customer of record must provide a copy of their State of Florida Agency of Healthcare Administration's Medicaid Program enrollment letter (Medicaid Eligibility Letter), or an alternative form of proof of enrollment acceptable to the Company, and proof of their date of birth. Witness Williams explained that since Medicaid is only open to low-income Florida residents, enrollment in Medicaid serves as proof of low-income status. Using the Medicaid Eligibility Letter and Medicaid income thresholds as eligibility criteria for the Senior Care Program avoids the need for TECO to income-qualify customers in-house. During cross-examination by FL Rising/LULAC, TECO witness Williams stated that in Hillsborough county over 26 percent of the population is on Medicaid, and 15 percent of the population is over the age of 65.

To explain why TECO chose that a customer must be 65 years old or older to qualify for the Senior Care Program, witness Williams testified that TECO needed an accurate metric for the potentially eligible population to forecast the number of potential participants and design the program. U.S. Census Bureau data is available for the percentage of the population in

Hillsborough County that is 65 years old or older, while other senior citizen age data was not available. TECO explained that the proposed Senior Care Program targets a particular subset of low-income households; furthermore, TECO stated that customers indicated that assisting low-income senior citizens were the two most important causes that they would like to see TECO support.

TECO proposed to fund the program via base rates and all customers would fund the program. MFR Schedule E-13c demonstrates the proposed program funding. MFR Schedule E-13c, line 17, shows the estimated costs to be $3,653,880.

Regarding the proposal to provide a $10 monthly bill credit, TECO considered programs offered by other utilities and different basic design approaches, i.e., fixed dollar credit versus per kWh credits. After reviewing options, TECO explained that it applied its judgment and determined that a $10 credit would assist participants by lowering their monthly bills while keeping the impact to non-participants reasonable.

Table 20 shows each rate class' estimated contribution.

Table 20
Senior Care Program Contributions by Rate Class

Rate Class	Senior Care Program Contribution
RS	$2,295,521
GS	$204,393
GSD	$851,563
GSLDPR	$98,648
GSLDSU	$64,120
LS Energy	$5,011
LS Facilities	$134,625
Total	**$3,653,880**

TECO offers another program to assist customers called the Share program. However, that donation program is funded by TECO shareholders, TECO employees, and customers *voluntarily* willing to donate. TECO shareholders match donations dollar-for-dollar up to $500,000. TECO employees are also encouraged to assist their neighbors through donations to the Share program but are not obligated to donate, and any customer of TECO's general body of ratepayers can voluntarily donate to TECO's Share program. No customer is obligated to donate to the Share program, unlike the proposed Senior Care Program. TECO explained that customers in need of financial assistance can apply for help through one of the Share administrators, which are the Salvation Army or Catholic Charities Diocese of St. Petersburg. The maximum amount of assistance provided is $450 per year, per customer.

If a customer meets the criteria for both the Share program and the Senior Care Program, they would be eligible for, and could receive, assistance under each program at the same time. Though not every customer that is eligible for the Share program receives funding from the Share program, because that program's financial resources are limited. With that said, if a Senior Care Program eligible customer were to receive the $450 annual allotment from the Share program, they would still be incentivized to receive an additional $10 monthly bill credit via the Senior Care Program.

FL Rising/LULAC took the position that TECO does need to care for its seniors and low-income customers; however, a reasonable cost of service and revenue requirement would lower bills for customers far more than $10, without having higher bills for all residential customers to provide a credit to a small group of customers.

As proposed, TECO's stockholders would not contribute to the Senior Care Program. However, TECO stockholders do assist low-income customers by contributing to TECO's Share program. If TECO wishes to assist a subset of customers with their energy bills, we find that the program should be funded by voluntary ratepayer and/or TECO employees and shareholder donations, similar to TECO's Share program. We do not find it appropriate for the general body of ratepayers to be required to subsidize TECO's proposed Senior Care Program.

2. Conclusion

We therefore deny the proposed Senior Care Program (Original Tariff Sheet No. 3.310) and associated cost recovery. Accordingly, TECO must remove the estimated costs and bill credits from the cost of service study. If TECO wishes to offer the proposed program involving a fixed $10 monthly bill credit to TECO's low-income customers 65 and older, the program should be funded through voluntary ratepayer donations and/or by TECO employees and TECO shareholders.

F. Polk Unit 1 / Big Bend 4 Studies (Issue 116)

1. Analysis

As discussed in Issue 24, TECO requested to convert Polk Unit 1 from an IGCC unit to a simple cycle CT unit, but while retaining the equipment that would let the unit to be converted back to an IGCC unit. This would allow the Company the opportunity to operate the unit using natural gas currently and potentially convert to unit to utilize petcoke in the case of future natural gas price increases. TECO has also stated its intent to continue the operation of Big Bend Unit 4 as a dual-fuel unit with coal-burning capacity.

Sierra Club witness Glick testified that TECO should study the economics of maintaining an adequate, but not excessive, capacity position to serve its customers. The witness further testified that TECO should proactively test the market with request for proposals to evaluate the replacement resource options. However, as discussed in Issue 24, we ordered the retirement of

Polk Unit 1's gasifier, HRSG, and ST—thereby eliminating fuel-switching as an option for Polk in the future.

Witness Glick asserted that TECO did not consider early retirements for the Polk and Big Bend units. The witness further asserted that Polk did not undergo an analysis that demonstrated that the Polk conversion was the most cost-effective option relative to retirement. The witness also asserted that Big Bend should be evaluated to be retired and replaced with renewable resources or use an alternative fuel source. During rebuttal, witness Aldazabal stated that TECO performed a CPVRR analysis that showed a savings of $24.6 million of the Polk conversion compared to a 2028 retirement date. We note that in Issue 24, we approved conversion of Polk Unit 1. In regard to Big Bend Unit 4, witness Aldazabal asserted that the Company had not performed an early retirement analysis of the unit as the fuel diversity and resiliency provided by the unit was necessary to mitigate natural gas fuel prices and supply interruption risk. The witness further explained that because Big Bend has at least 15 years of remaining useful life, it would be premature to incur the costs associated with developing cost estimates and system impacts of repowering the unit.

Sierra Club was the only party that offered testimony regarding this Issue. In its brief, it reiterated its argument that TECO should be required to perform the additional studies for the units in this Issue. FRF argued that in the current regulatory environment TECO should be pursing evaluations of its unit's ability to be retired early. FL Rising/LULAC and Walmart adopted Sierra Club's and FRF's positions, respectively. All other intervenors took no position on this Issue.

In our view, it is important for utilities to continually evaluate the factors surrounding the retirement and addition of generating units, such as reliability, economic, and regulatory impacts. We find that the testimony and evidence from TECO witness Aldazabal on this Issue to be credible and persuasive. The record shows that TECO has given reasonable consideration of these factors in its continued operations. Therefore, the economic resource evaluation proposed by Sierra Club witness Glick would be duplicative of normal business operations. Therefore, we find that no additional analysis of early retirement dates for Polk Unit 1 and Big Bend Unit 4 are necessary.

2. Conclusion

TECO is responsible for continuously evaluating its generating fleet for reliability, economics, and compliance with applicable regulations. Based on the record, TECO has performed reasonable analysis in regards to the early retirement of Polk Unit 1 and Big Bend Unit 4 and no further studies are needed at this time.

G. Rate and Charges Effective Date (Issue 117)

1. Analysis and Conclusion

We find TECO provided notice of its proposed 2025 rates to customers with the first billing cycle of December 2024. TECO shall post our approved rates on its website. These rates and charges shall become effective the first billing cycle in January 2025.

H. Florida Energy and Efficiency Conservation Act Performance (Issue 118)

1. Analysis

In 1980, the Florida Legislature approved the Florida Energy and Efficiency Conservation Act (FEECA), which consists of Sections 366.80 through 366.83 and Section 403.519, F.S. Collectively, these statues are referenced herein as the "FEECA statutes." Under FEECA, this Commission is required to set appropriate goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems for electric utilities of a certain size, which includes TECO.

In its brief, TECO asserts that since the FEECA statutes were enacted in 1980, its goal achievement performance has saved the equivalent of over seven 180 MW power generating stations. FL Rising/LULAC argue that we should consider TECO's goal achievement performance when establishing rates. They contends this Commission has a duty to do so in this case. FL Rising/LULAC state that TECO's FEECA performance is adequate when compared to other utilities across the United States or to national standards. No other intervenor offered a position on this Issue.

Section 366.82(10), F.S., requires this Commission to "consider the performance of each utility pursuant to [the FEECA statutes] when establishing rates for those utilities over which the [C]omission has ratesetting authority." TECO submits periodic (annual) reports to us, pursuant to the obligation set forth in Section 366.82(10), F.S. The annual filing summarizes its goal achievement performance from the prior year.[88] In addition, TECO participates in the FEECA demand side management goalsetting proceeding every five years, the most recent of which concluded earlier in 2024.[89]

We have reviewed Exhibit 220, which contains the yearly FEECA reports for 2021, 2022, and 2023. In 2021, TECO did not achieve its performance goal for Residential Summer MW reduction and Residential Winter MW reduction, but achieved every other goal in that review period. In 2022, TECO did not achieve its performance goal for Residential Winter MW

[88] Data from TECO and other utilities is published in the Commission's Annual Report on Activities Pursuant to the Florida Energy and Efficiency Conservation Act (FEECA Report). Current and historic FEECA Reports are accessible via the Commission's website, and hearing Exhibit 220 is a composite of FEECA Reports from 2021, 2022, and 2023.

[89] TECO was an active participant in the goal-setting proceeding, which concluded earlier in 2024. See Docket No. 20240014-EG, *In re: Commission review of numeric conservation goals (Tampa Electric Company)*.

reduction and Total Winter MW reduction, but again achieved all other goals in that review period. Since 2020, TECO has only fallen short of its goal achievements in 2021 and 2022, years when COVID-related concerns prompted constraints on TECO and other utilities' abilities to offer all programs throughout the year.[90] Given these circumstances, we find TECO has consistently met its FEECA goals.

2. Conclusion

In setting rates in this proceeding, we considered TECO's FEECA performance since the last rate case, and we conclude that TECO met the vast majority of its goals.

I. Affordability and Rate Impact (Issue 119)

1. Analysis

a. Affordability

This Commission can consider the "affordability" of bills in this proceeding, but it may do so only within the confines of its "fair, just, and reasonable" rates standard in Section 366.06(1), F.S.[91] In order to effectuate a determination of fair, just, and reasonable, the Commission considers a number of factors (which may vary slightly from case to case). These could include, for example, whether:

- Projects proposed by a utility are truly needed;[92]
- Costs are reasonably and prudently incurred;[93]
- Plans of action appear to be cost-effective;[94]
- Projects will be used and useful in the time rates are charged;[95]
- Activities contribute to the security and reliability of Florida's energy grid;[96]
- A utility's FEECA performance is adequate;[97]
- The rate of return is reasonable in light of legal standards and all the evidence presented;[98]

[90] Full goal achievement results are in the archived FFECA Reports accessible via floridapsc.com.
[91] OPC, FRF, and Walmart appear to agree that "affordability," to the extent it can be considered, must be looked at within the "fair, just, and reasonable" rates standard. Contrary to the insinuations of OPC and FL Rising/LULAC, Florida's energy policy goals in Section 377.601, F.S., do not expand the Commission's traditional cost of service ratemaking authority. Goals are generally aspirational in nature—things that can be worked toward when practicable and legally permissible to do so within existing statutory frameworks.
[92] *See* Section 366.06(1)–(2), F.S.; Section 366.07, F.S.
[93] Section 366.06(1), F.S.
[94] *See id.*
[95] *Id.*
[96] *See* Section 366.04(2)(c), F.S.; Section 366.055(1), F.S.
[97] Section 366.82(10), F.S.
[98] Section 366.06(2), F.S.

- The cost of providing service to the rate class;[99] and
- Value of service.[100]

Furthermore, pursuant to Section 366.041(1), F.S., we have the discretion to consider the "efficiency, sufficiency, and adequacy of the facilities provided and the services rendered," the ability of the utility to improve service and facilities, energy conservation, and the efficient use of alternative energy resources. The aforementioned factors are typically discrete issues supported by testimony and evidence. Looking at base rate changes through this lens results in rates that are fair, just, and reasonable for both the public utility and for TECO's general body of ratepayers.

In this case, OPC, FL Rising/LULAC, FRF, Walmart, and FIPUG argue that our decision should rest on whether customers' utility bills are affordable. OPC and FL Rising/LULAC (hereinafter Proponents) would have us evaluate whether an individual household has enough money to pay their utility bill given the proposed rate increase. In essence, this type of inquiry would require a case-by-case analysis of a customer's utility bill and would require consideration of factors invented by us, and not authorized by statute. In fact, the evidence shows that Proponents' definitions of affordability vary from person to person and household to household. For example, two families with the same income and utility bill amount may view affordability of electricity differently based on their different circumstances. "Affordability" is therefore a subjective term.

TECO's customers expressed a broad range of experiences and concerns regarding the affordability of electric bills. Many customers pointed to how inflation has impacted them. Other customers expressed that higher bills might cause them to shift their spending priorities. Customers pointed to the lack of universal healthcare and high prices for food, medicine, and housing as budget-stressors. One customer suggested that while solar energy development may not fix everything, it could help alleviate the burden of customer bills.

Affordability of utility bills depends on many factors beyond the control of a utility or this Commission, such as: idiosyncratic perceptions, personal electricity usage choices, income levels, inflation, financial obligations, housing, transportation choices, spending priorities, and spending decisions. Overall, customers seemed to ask us to scrutinize TECO's proposed rate increase on the basis of fairness, reasonableness, and need.

Notwithstanding that the word "affordable" is not defined, let alone referenced, in Chapter 366, F.S., there does not appear to be any universally accepted definition of affordability either. TECO witness Williams, OPC witness Dismukes, and FL Rising/LULAC witness Rábago, each approached and analyzed the topic differently. Essentially, as noted previously, Proponents argue for an individual budget-type, household analysis that is not contained in Chapter 366, F.S. TECO disagrees with the metrics proposed by the Proponents. To demonstrate the shortcomings of the Proponents' analyses, TECO witness Williams assumed for sake of

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[99] Section 366.06(1), F.S.
[100] *Id.*

argument a 6 percent energy burden proxy and used over two decades of data (in addition to the 2025 projected test year) to conclude the energy burden for a low-income, two-person household on TECO's proposed rates would be 4.5 percent. This falls below the energy burden standard adopted by OPC witness Dismukes. Furthermore, FL Rising/LULAC witness Rábago failed to account for differences in other states' average customer bills where customers rely on natural gas or oil for winter heating, rather than electricity, thereby contributing to lower overall electricity bills in other states. This apples to oranges comparison is thus flawed.

Furthermore, OPC witness Dismukes testified that other jurisdictions have addressed the concept of energy "affordability," like Pennsylvania and California, but those states have different enabling legislation than Florida and can be distinguished. For example, Pennsylvania has a mandate that low-income customers have access to affordable electricity, including through low-income assistance programs funded through a universal statewide charge on all non-program participants.[101] Meanwhile, California law expressly authorizes the California Public Utilities Commission to consider the affordability of electricity, gas, water, and telecommunications rates,[102] unlike our existing laws in Florida.[103] California, like Pennsylvania, has expressly authorized its utility commission to establish assistance programs that subsidize low-income electric customers.[104] For these reasons, we find OPC witness Dismukes' attempted analogies to how other jurisdictions have addressed "affordability" unpersuasive.

TECO gave affordability consideration in its operating and planning decisions. The record is replete with its efforts to do so in a manner rooted in traditional factors of cost-effectiveness, reliability, and reasonableness. The Board of Directors was informed about ways that high utility bills place financial and social pressures on customers. The Board was presented with many ways to keep customer costs down, like leveraging tax credits. TECO took concrete steps to create fuel savings for customers. It made infrastructure decisions that promoted reliability so operating costs passed along to customers would be reduced. TECO also invests in technology to drive down costs. These are but a few of the ways TECO witness Chronister testified the Company takes affordability into consideration. While Proponents characterize

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[101] *Retail Energy Supply Ass'n v. Penn. Public Utility Comm'n*, 185 A.3d 1206, 1210 (Pa. Commw. Ct. 2018); *see also* 66 Pa. C.S. §§ 2801–2815 (codifying Pennsylvania's Electricity Generation Customer Choice and Competition Act).

[102] CA Pub. Util. Code § 739(d)(2) ("In establishing residential electric and gas rates, including baseline rates, the commission shall ensure that the rates are sufficient to enable the electrical corporation or gas corporation to recover a just and reasonable amount of revenue from residential customers as a class, while observing the principle that electricity and gas services are necessities, for which a low *affordable rate* is desirable and while observing the principle that conservation is desirable in order to maintain and *affordable* bill.") (emphasis added); CA Pub. Util. Code § 739.8(a)–(b) ("Access to an adequate supply of healthful water is a basic necessity of human life, and shall be made available to all residents of California at an *affordable* cost. The commission shall consider and *may implement programs* to provide rate relief for low-income ratepayers.") (emphasis added); CA Pub. Util. Code § 871.5(a) ("The offering of high-quality basic telephone service at *affordable* rates to the greatest number of citizens has been a longstanding goal of the state. The Moore Universal Telephone Service Act has been, and continues to be, an important means for achieving universal service by making basic telephone service *affordable* to low-income households through the creation of a lifeline class of service.") (emphasis added).

[103] Although Florida facilitates the provision of Lifeline service in the State, pursuant to Section 364.10, F.S., we have not had ratemaking authority over telecommunications companies for many years.

[104] CA Pub. Util. Code § 739.1.

TECO's proposed rates as being "unaffordable," as they would define that term, TECO provides more persuasive testimony and evidence that its proposed rates are "affordable" because it does so within the context of this Commission's existing fair, just, and reasonable statutory standard which considers the factors identified earlier in this analysis.

b. Rate Impact

The term "rate impact" appears in our statutes and rules, albeit in the context of Storm Protection Plans.[105] It is a final calculated number that shows the change in rates. Each individual customer may feel the effect differently, depending upon their individual circumstances, but the rate impact is the same for all customers within a class.

TECO provided typical bill comparisons for its major rate schedules in MFR Schedule A-2. By way of illustrative example, for a residential customer using 1,000 kWh per month (a benchmark commonly used to compare bills), TECO's proposed revenue increase would have increased the base rate portion of monthly bills in 2025 from $87.80 to $107.01—a rate impact of $19.20. However, due to our adjustments and denying some of TECO's requests, the rate impact on those customers will be $9.67 instead.[106]

Regardless, to the extent we consider affordability, it should be within the scope of our statutory mandate to consider whether proposed rates are fair, just, and reasonable. In evaluating this statutory mandate we may consider affordability from the perspective of analyzing rate impact across-the-board, i.e. the impact of the proposed rate increase on the average base rate portion of the monthly bills.

2. Conclusion

This Commission has broad discretion to carry out its legislative mandate of ensuring rates are fair, just, and reasonable. However, there exists no statutory authority to infer a specific definition of affordability absent express legislative authorization.[107] To the extent we can consider the "affordability" of customer bills, we must do so within the context of our governing statutes in Chapter 366, F.S. OPC and FL Rising/LULAC offered standards/tests for affordability that appear to be beyond this Commission's statutorily delegated authority. We are persuaded, however, by the evidence TECO offered that TECO's proposed requests are affordable to the extent that we find those rates to be fair, just, and reasonable. We further note that because of our adjustments, customers are estimated to experience a smaller rate impact by comparison.

[105] Section 366.96(4)(d), F.S.; Rule 25-6.030(3)(h), F.A.C.
[106] A customer's total bill includes various adjustment clauses, such as fuel, storm hardening, and storm restoration, in addition to base rates. Those clause factors are established by the Commission in other proceedings.
[107] *See* Section 120.52(8), F.S.

J. Commission-Ordered Adjustments (Issue 120)

1. Analysis and Conclusion

Consistent with our practice, TECO shall 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 are required as a result of our findings in this rate case.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Tampa Electric Company's Petition for Rate Increase is GRANTED IN PART and DENIED IN PART as set forth herein. It is further

ORDERED that each finding made in the body of this Order is hereby approved in every respect. The rates approved by us are fair, just, and reasonable. It is further

ORDERED that all matters contained in the attachments and schedules appended hereto are incorporated by reference. It is further

ORDERED that the revised tariffs submitted by Tampa Electric Company and the final rates and charges contained therein, as incorporated and attached to this Order, are hereby approved. It is further

ORDERED that the approved rates and charges for Tampa Electric Company shall be effective for the first billing cycle in January 2025. It is further

ORDERED that in September 2025, Tampa Electric Company shall file its proposed 2026 Subsequent Year Adjustment rates, consistent with our decision herein. Tampa Electric Company shall verify the in-service dates of all projects and use then-current billing determinants. Once approved, those rates shall become effective for the first billing cycle in January 2026. It is further

ORDERED that in September 2026, Tampa Electric Company shall file its proposed 2027 Subsequent Year Adjustment rates, consistent with our decision herein. Tampa Electric Company shall verify the in-service dates of all projects and use then-current billing determinants. Once approved, those rates shall become effective for the first billing cycle in January 2027. It is further

ORDERED that Tampa Electric Company shall file, within 90 days after the issuance of this Order, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which are required as a result of our findings in this rate case. It is further

ORDERED that after this Order is issued, Docket Nos. 20230090-EI, 20230139-EI, and 20240026-EI shall be closed.

By ORDER of the Florida Public Service Commission this 3rd day of February, 2025.

ADAM J. TEITZMAN
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399
(850) 413-6770
www.floridapsc.com

Copies furnished: A copy of this document is provided to the parties of record at the time of issuance and, if applicable, interested persons.

CMM/TPS

DISSENTS

Commissioner Andrew Giles Fay dissents with respect to the Commission's decision to approve a ROE of 10.5% (Issue 39), to approve the 4 CP methodology (Issues 71 and 72), and to approve the Polk Fuel Diversity Project (Issue 102).

Commissioner Gabriella Passidomo Smith dissents with respect to the Commission's decision to deny the Future Environmental Compliance Project (Issue 14), to approve the 4 CP methodology (Issues 71 and 72), and to approve the Polk Fuel Diversity Project (Issue 102).

COMMISSIONER PASSIDOMO SMITH, dissenting with a separate opinion:

I respectfully dissent from the majority with respect to the method of production and transmission cost allocation (Issues 71 and 72).

In my opinion, the 12 CP and 1/13 AD method provides a more reasonable allocation for production costs to TECO's customers. TECO's witness, Jordan Williams, acknowledged an advantage of the 12 CP methodology is that it recognizes that TECO is required to serve load throughout the entire year, including shoulder months, not just the 4 CP months chosen by TECO (i.e., June, July, August, and January). Furthermore, the approved 4 CP method shifts more costs away from larger commercial and industrial customers onto the residential and small commercial rate classes, while some of the larger commercial and industrial customers also receive the benefit of interruptible credits. Any arguments that 4 CP has potential economic development benefits are less compelling because TECO has other tools to attract new business, including the Economic Development and Commercial/Industrial Service Riders.

Therefore, the more traditional 12 CP and 1/13 AD method of production cost allocation and the 12 CP method of transmission cost allocation are more appropriate in this case than the proposed 4 CP method adopted by the majority.

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas, or telephone utility by filing a notice of appeal with the Office of Commission Clerk, and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

ATTACHMENT A

Tampa Electric Company
DOCKET NO. 20240026-EI
13-MONTH AVERAGE RATE BASE (Dollars in 000's)
DECEMBER 2025 TEST YEAR

Issue No.		Plant in Service	Accumulated Depreciation	Net Plant in Service	CWIP	Plant Held for Future Use	Net Plant	Working Capital	Total Rate Base
	Adjusted per Company	13,418,078	4,004,807	9,413,271	230,175	68,034	9,711,480	86,671	9,798,150
	Commission Adjustments:								
15	Remove Customer Experience Projects	(13,400)	(893)	(12,507)			(12,507)		(12,507)
16	Remove Microgrid Project	(2,800)	(97)	(2,703)			(2,703)		(2,703)
14	CCS Eval			-	(12,190)		(12,190)		(12,190)
24	Retire Portions of Polk 1 Flexibility	(456,823)	(314,571)	(142,252)			(142,252)		(142,252)
24	Early Retirement of Polk 1 Flexibility			-			-	129,320	129,320
31	To reflect amortization of Generation O&M			-			-	8,200	8,200
64	PTC Amortization adjustment			-			-	(220)	(220)
7	35-yr Solar, 20-yr Energy Stor., 40-yr 367		(8,744)	8,744			8,744		8,744
11	Solar accrual (35-yr) and Inflation factors		(836)	836			836		836
	Total Commission Adjustments	(473,023)	(325,142)	(147,881)	(12,190)	-	(160,071)	137,300	(22,771)
	Fall Out - Commission Approved Rate Base	12,945,055	3,679,665	9,265,390	217,985	68,034	9,551,409	223,971	9,775,379

ATTACHMENT B

Tampa Electric Company
DOCKET NO. 20240026-EI
13-MONTH AVERAGE CAPITAL STRUCTURE (Dollars in 000's)
DECEMBER 2025 TEST YEAR

Company As Filed	($) Amount	Ratio	Cost Rate	Weighted Cost
Long Term Debt	3,536,333	36.09%	4.53%	1.63%
Short Term Debt	376,625	3.84%	3.90%	0.15%
Customer Deposits	99,195	1.01%	2.41%	0.02%
Preferred Stock	-	0.00%	0.00%	0.00%
Common Equity	4,593,473	46.88%	11.50%	5.39%
Deferred Income Taxes	980,855	10.01%	0.00%	0.00%
Tax Credits - Zero Cost	-	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	211,669	2.16%	8.26%	0.18%
Total	9,798,150	100.00%		7.38%
Equity Ratio	54.00%			

Commission Approved	($) Company As Filed Amount	($) Specific Adjustments	($) Adjusted Total	Ratio	($) Pro Rata Adjustments	($) Commission Adjusted	Ratio	Cost Rate	Weighted Cost
Long Term Debt	3,536,333		3,536,333	36.10%	(7,533)	3,528,800	36.10%	4.53%	1.64%
Short Term Debt	376,625		376,625	3.84%	(802)	375,823	3.84%	3.90%	0.15%
Customer Deposits	99,195		99,195	1.01%	(211)	98,984	1.01%	2.41%	0.02%
Preferred Stock	-		-	0.00%	-	-	0.00%	0.00%	0.00%
Common Equity	4,593,473		4,593,473	46.89%	(9,785)	4,583,688	46.89%	10.50%	4.92%
Deferred Income Taxes	980,855	(259)	980,596	10.01%	(2,089)	978,507	10.01%	0.00%	0.00%
Tax Credits - Zero Cost	-		-	0.00%	-	-	0.00%	0.00%	0.00%
Tax Credits - Weighted Cost	211,669	(1,643)	210,026	2.14%	(447)	209,579	2.14%	7.90%	0.17%
Total	9,798,150	(1,902)	9,796,248	100.00%	(20,869)	9,775,379	100.00%		6.90%
Equity Ratio	54.00%								

ATTACHMENT C

Tampa Electric Company
DOCKET NO. 20240026-EI
NET OPERATING INCOME (Dollars in 000's)
DECEMBER 2025 TEST YEAR

Issue No.		Operating Revenues	O&M Other	O&M - Fuel	Depreciation and Amortization	Taxes Other Than Income	Total Income Taxes	(Gain)/Loss on Disposal of Plant	Total Operating Expenses	Net Operating Income
Issue	Adjusted per Company	1,518,472	391,771	626	531,436	101,592	(8,327)	-	1,017,099	501,372
No.	Commission Adjustments:									
7	35-yr Solar, 20-yr Energy Stor., 40-yr 367				(18,937)		4,800		(14,137)	14,137
11	Solar accrual (35-yr) and Inflation factors				(1,672)		424		(1,248)	1,248
15	Customer Experience Projects		(3,140)		(893)		1,022		(3,011)	3,011
16	Microgrid Project				(97)		25		(73)	73
24/43	Polk 1 Flexibility Retirement		11,432		(2,010)		(2,388)		7,034	(7,034)
45	Generation O&M Reduction		(8,270)				2,096		(6,174)	6,174
53	Remove SERP		(107)				27		(80)	80
55	Remove 1/2 Corp Resp.		(3,810)				966		(2,844)	2,844
56	Reduce D&O Liab Insurance (50%)		(151)				38		(113)	113
64	PTC Amortization adjustment		(11,636)				2,949		(8,687)	8,687
65	ITC 10-yr Amort.						(2,883)		(2,883)	2,883
62	Fallout Adj. - Parent Debt						(570)		(570)	570
63	PTC Rate						(3,217)		(3,217)	3,217
	Interest Syncronization						143		143	(143)
	Total Commission Adjustments	-	(15,682)	-	(23,610)	-	3,431	-	(35,861)	35,861
	Fall Out - Commission Adjusted NOI	1,518,472	376,089	626	507,826	101,592	(4,896)	-	981,238	537,233

ATTACHMENT D

Tampa Electric Company
DOCKET NO. 20240026-EI
NET OPERATING INCOME MULTIPLIER

Line No.		2025 (%) As Filed	2025 (%) Commission Approved
1	Revenue Requirement	100.000	100.000
2	Regulatory Assessment Fee	(0.085)	(0.0848)
3	Bad Debt Rate	(0.224)	(0.224)
4	Net Before State Income Taxes (L1 + L2 +L3)	99.691	99.691
5	State Income Tax (L17)	5.483	5.483
6	Net Before Federal Income Taxes (L4 - L5)	94.208	94.208
7	Federal Income Tax (L25)	19.784	19.784
8	Revenue Expansion Factor (L6 - L7)	74.424	74.424
9	Net Operating Income Multiplier (100% / L8)	1.34365	1.34364

Attachment E
Page 1 of 1

ATTACHMENT E

Tampa Electric Company
DOCKET NO. 20240026-EI
DECEMBER 2025 PROJECTED TEST YEAR (Dollars in 000's)
OPERATING REVENUE REQUIREMENT INCREASE CALCULATION

Line No.		As Filed	Commission Approved
1	Rate Base	$9,798,150	$9,775,379
2	Overall Rate of Return	7.38%	6.90%
3	Required Net Operating Income (1)x(2)	723,008	674,741
4	Achieved Net Operating Income	501,372	537,233
5	Net Operating Income Deficiency (3)-(4)	221,636	137,508
6	Net Operating Income Multiplier	1.34365	1.34364
7	Operating Revenue Increase (5)x(6)	$297,802	$184,762
8	Difference		($113,040)

TECO TAMPA ELECTRIC
AN EMERA COMPANY

EIGHTEENTH REVISED SHEET NO. 3.010
CANCELS SEVENTEENTH REVISED SHEET NO. 3.010

MISCELLANEOUS

SCHEDULE	TITLE	SHEET NO.
	Budget Billing Plan (Optional)	3.020
	Summary Billing Plan (Optional)	3.025
	Service Charges	3.030
	Home Energy Analysis	3.040
	Commercial and Industrial Energy Analysis	3.050
GSLM-1	General Service Load Management Rider	3.150
GSSG-1	Standby Generator Rider	3.200
GSLM-2	General Service Industrial Load Management Rider	3.210
GSLM-3	General Service Industrial Standby and Supplemental Load Management Rider	3.230
BERS	Building Energy-Efficient Rating System	3.250
NM-1	Net Metering Service	3.255
RE	Renewable Energy Program (Sun to Go) (Optional)	3.270
NSMR-1	Non-Standard Meter Service Rider (AMI Opt-Out) (Optional)	3.280
SSR-1	Shared Solar Rider (Sun Select)	3.300

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 3.020
CANCELS FOURTH REVISED SHEET NO. 3.020

BUDGET BILLING PLAN

(OPTIONAL)

Tampa Electric's Budget Billing Plan offers customers the opportunity, by electing to participate in the program, to better stabilize their monthly bill payments to the company by making budgeted (predetermined and company-calculated) monthly payments to the company.

Tampa Electric's optional Budget Billing Plan program is only available to customers taking electric service under the company's Residential Service (RS) or General Service – Non Demand (GS) Rate Schedules. Participation is limited to customers that Tampa Electric determines are in good financial standing. In determining whether a customer is in good financial standing, the company will consider factors such as whether the customer has an overdue balance, whether the customer has a pending service disconnection for non-payment, whether the customer has a history of late payment or returned payments for insufficient funds, or other similar factors. If the requesting customer has not received continuous electric service from the company, at the requesting location, for the preceding 12 months, the company may deny enrollment. Tampa Electric also retains the option to remove customers from the program if customers do not remain in good financial standing.

Tampa Electric shall have 30 days following a customer's request to deny or implement participation in the program.

If a customer requests to participate in the program, the initial budgeted payment amount will be based on an average of the previous twelve months' consumption. The company may adjust the initial budgeted payment amount for any known consumption changes or known rate changes and may include applicable taxes and fees. The company may begin charging the recalculated amount on the customer's next successive bill. The company will perform periodic reviews quarterly.

Any current and total deferred balance will be shown on the customer's bill. When a customer's budgeted payment amount is recalculated, any debit deferred balance will be embedded into the customer's budgeted monthly payment; any deferred credit amount will be credited to the customer's account only during an annual true-up period.

An electing customer's participation in the Budget Billing Plan will be continuous unless the customer requests that participation in the plan be terminated, electric service is terminated, or the company elects to terminate the customer from participating in the program. At the time of termination, the customer must settle their account with the company in full; customers who remain a customer of the company must pay any deferred debit balance with their next regular monthly bill, and any deferred credit balance will be used to reduce the amount due for their next regular monthly bill. At any time, a participating customer may request to terminate participation in the program. Any customer terminated from the program by the company or any customer who voluntarily terminates participation in the program may not rejoin the program for at least twelve (12) months.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 3.030
CANCELS THIRTEENTH REVISED SHEET NO. 3.030

SERVICE CHARGES

1. For purposes of all these charges, normal working hours are Monday through Friday, 7:00 a.m. to 6:00 p.m., excluding holidays.

2. An Initial Connection Charge of $168.00 is applicable for the initial establishment of service to a premises. Initial connect may only occur during normal working hours.

3. A Connection Charge shall apply to the subsequent re-establishment of service to a premises for which service has not been disconnected due to non-payment or violation of Company or Commission Rules.

   a. A Connection Charge of $15.00 shall apply to the re-establishment of service to a premises.
   b. For all customers who have remote connect capability in their meter, and who contact Tampa Electric during normal working hours, can schedule this service for same day, Saturdays, Sundays and Holidays. Service times will be scheduled by Tampa Electric.
   c. This service is not available for Opt-Out customers and for all other customers who do not have remote connect capability in their meter except during normal working hours.

4. A Reconnect after Disconnect Charge shall apply to the re-establishment of service after service has been disconnected due to non-payment or violation of Company or Commission Rules. Service under these charges will only occur once payment of the un-paid amount owed has been received by Tampa Electric. or the violation has been corrected.

   a. For service which has been disconnected at the point of metering, the Reconnect after Disconnect Charge is $18.00.
   b. For all customers who have remote connect capability in their meter, and who contact Tampa Electric during normal working hours, can schedule this service for same day, Saturdays, Sundays and Holidays. Service times will be scheduled by Tampa Electric.
   c. This Reconnect after Disconnect service at the point of metering is not available for Opt-Out customers and for all other customers who do not have remote connect capability in their meter except during normal working hours.
   d. For service which has been disconnected at a point distant from the meter, the Reconnect after Disconnect Charge is $175.00. This service is only available during normal working hours.

5. A Field Visit Charge of $37.00 may be assessed and applied to the customer's first billing for service at a particular premises following the occurrence of any of the events described below:

Continued to Sheet No. 3.032

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 3.032
CANCELS SECOND REVISED SHEET NO. 3.032

Continued from Sheet No. 3.030

a. A Company representative visits the premises for the purpose of disconnecting service due to non-payment and instead makes other payment arrangements with the customer.
b. The customer has requested service to be initially connected or reconnected and the Company upon arrival finds the premises is not in a state of readiness or acceptable condition to be energized.
c. The customer or his representative has made an appointment with the Company to discuss the design, location, or alteration of his service arrangement at the premise and the Company maintains such an appointment, but finds the customer/representative is not present for such discussion.

5. A Returned Check Charge as allowed by Florida Statute 68.065 shall apply for each check or draft dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the Returned Check Charge.

6. Charges for services due and rendered which are unpaid as of the past due date are subject to a Late Payment Charge. The Late Payment Charge for non-governmental accounts shall be the greater of $5.00 or 1.5% for late payments over $10.00 and 1.5% for late payments $10.00 or less. Accounts of federal, state, and local governmental agencies and instrumentalities are subject to a Late Payment Charge at a rate no greater than allowed, and in a manner permitted, by applicable law.

7. A Tampering Charge of $75.00 is applicable to a customer for whom the Company deems has undertaken unauthorized use of service and for whom the Company has not elected to pursue full recovery of investigative costs and damages as a result of the unauthorized use. This charge is in addition to any other service charges which may be applicable.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

RENEWABLE ENERGY PROGRAM

(OPTIONAL)
(Sun To Go)

SCHEDULE: RE

RATE CODE: 910

AVAILABLE: To all customers served throughout the Company's service area.

APPLICABLE: Applicable, upon request, to all customers in conjunction with all standard rates. Customer billing will start on the next billing cycle following receipt of the service request.

CHARACTER OF SERVICE: Renewable Energy Rider customers will be served from the existing electrical system. Customers may purchase 200 kWh blocks of renewable energy produced at or purchased from photovoltaic facilities, facilities utilizing biomass fuel, and/or specifically delivered from other clean, renewable energy sources. The renewable energy may not be delivered to the customer, but will displace energy that would have otherwise been produced from traditional fossil fuels.

LIMITATION OF SERVICE: Customers requesting service under the rider will be accepted on a first-come first-served basis subject to availability of renewable energy. If additional renewable energy is not available, customers requesting service under the optional rider may request to be put on a waiting list until additional renewable energy can be secured to serve request.

MONTHLY RATE: $5.00 per 200 kWh premium in addition to charges applied under otherwise applicable rate schedules.

TERM OF SERVICE: Service under the RE rider shall be for a minimum term of one (1) billing period.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 3.300
CANCELS FIRST REVISED SHEET NO. 3.300

SHARED SOLAR RIDER
(Sun Select)

SCHEDULE: SSR – 1

AVAILABLE: At the option of the customer, available to residential, commercial and industrial customers per device (non-totalized or totalized electric meter) on rate schedules RS, GS, GSD, GSLDPR and GSLDSU on a first come, first served basis subject to subscription availability. Not available to customers who take service under NM-1, RSVP-1, any standby service or time of use rate schedule. Subscription availability will be dependent on availability of the Shared Solar facility. Customers who apply when availability is closed will be placed on a waiting list until Shared Solar capacity becomes available. The Shared Solar facility will be for 17.5 MWac* capacity and full subscription will be when 95% of expected annual energy output has been subscribed.

APPLICABLE: Applicable, upon request, to eligible customers in conjunction with their standard rates and availability of service subject to subscription availability.

CHARACTER OF SERVICE: Shared Solar - 1 (SSR-1) enables customers to purchase monthly energy produced from Company-owned solar facilities for a selected percentage of that month's billed kWh. For RS and GS, individual subscriptions will be measured as a percentage of the monthly energy consumption as selected by the customer: 25%, 50% or 100% rounded up to the next highest kWh. For GSD, GSLDPR and GSLDSU, a fixed kWh subscription in 1,000 kWh blocks will be identified by the customer not to exceed their average monthly kWh consumption for the previous 12-months at the time of subscription.

MONTHLY RATE: $0.063 per kWh for monthly energy consumption.

The monthly SSR-1 rate, multiplied by the monthly energy consumption selected by the customer, will be charged to the customer in addition to the customer's normal cost of electricity pursuant to their RS, GS, GSD, GSLDPR and GSLDSU tariff charges applied to their entire monthly billing determinants, with the exception of the Fuel Charge, which is normally billed under the applicable tariff. Tampa Electric will seek to maintain the SSR-1 energy rate at $0.063 per kWh or lower until January 1, 2048, however the SSR-1 energy rate will remain subject to change by order of the Florida Public Service Commission.

Under SSR-1, the Fuel Charge for the applicable RS, GS, GSD, GSLDPR and GSLDSU tariff, for the monthly energy percentage or blocks selected by the customer, will be billed at a rate of $0.00 per kWh provided under this rider. The Fuel Charge applies to the remainder of the monthly billing determinates.

Continued to Sheet No. 3.305

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

Continued from Sheet No. 5.060

2.2.1 CUSTOMERS RESPONSIBILITIES

All property of the Company installed in or upon the customer's premises used and useful in supplying service is placed there under the customer's protection. All reasonable care shall be exercised to prevent loss or damage to such property, ordinary wear and tear excepted.

The customer's responsibility includes: all wires, fittings, fixtures, breakers, outlets, appliances and apparatus of every type located on the Customer's side of the Delivery Point and used in connection with or forming a part of an installation for utilizing electricity for any purpose. Metering, regulating and other similar equipment remains the property of the Company.

The customer's wiring, fittings, fixtures, breakers, outlets, appliances and apparatus shall be installed and maintained in accordance with standard practice, and in full compliance with all applicable laws, codes and governmental and Company regulations. The Customer expressly agrees to utilize no apparatus or device which is not properly constructed, controlled, and protected, or which may adversely affect the Company's equipment or service to others, and the Company reserves the right to discontinue or withhold service for such apparatus or device.

The customer will be held responsible for breaking the seal, tampering or interfering with the Company's meter or meters or other equipment of the Company installed on the customer's premises. No one, except employees of the Company, will be allowed to make any repairs or adjustments to any meter or other piece of apparatus belonging to the Company.

The Company shall not be liable for any property damage, fatality, or personal injury sustained on the Customer's premises resulting from the Customer's Installation or the fittings, appliances, or apparatus of any type on Customer's premises. The Company will not be responsible for the use, care, or handling of electricity once the electricity passes the Delivery Point.

Resale of electrical energy by the Customer is not permitted.

Continued to Sheet No. 5.071

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

ORIGINAL SHEET NO. 5.071

Continued from Sheet No. 5.070

2.2.1.1 ACCESS TO PREMISES AND INTERFERENCE WITH COMPANY'S FACILITIES

The company and its agents, contractors, and representatives shall have access to the premises of the Customer at all reasonable times for the purpose of installing, maintaining, repairing, and inspecting or removing the company's property, reading meters, trimming trees, and other purposes incident to the provision of electrical service or performance or termination of the company's provision of service to the Customer. The company and its agents, contractors, and representatives shall not be liable to the Customer for trespass. The Customer is responsible for contacting the Company for guidance before constructing any items which may obstruct the Company's access. The Customer should not allow trees, vines, shrubs, or other vegetation to interfere with the Company's electric service equipment, including adjacent overhead conductors, service wires, pad mounted transformers, and meter. Such interference may result in an injury to persons or fatality, or may cause the Customer's service to be interrupted. Except for around service wires and when specifically authorized and arranged with the Company, Customers shall not trim or remove trees and other growth near the Company's adjacent overhead wires. If Customer believes that it is necessary or appropriate to trim or remove trees and other growth near the Company's adjacent overhead wires, Customer shall contact the Company within a reasonable time prior to commencing such work.

2.2.1.2 CONJUNCTIVE BILLING

Conjunctive billing means totalizing metering, additive billing, plural meter billing, conjunctional metering, and all like or similar billing practices which seek to combine, for billing purposes, the separate consumptions and registered demands of two or more points of delivery serving a single Customer.

A single point of delivery of electric service to the user of such service is defined as the single geographical point where a single class of electric service, as defined in a published rate tariff, is delivered from the facilities of the utility to the facilities of the Customer. Conjunctive billing shall not be permitted. Bills for two or more points of delivery to the same Customer shall be calculated separately for each such point of delivery.

Continued to Sheet No. 5.075

Continued from Sheet No. 5.071

Totalized metering may be authorized by the company on such installations of electric service where single circuit metering equipment is impractical because of the Customer's load and the standard electrical equipment utilized by the company. Totalized metering will be considered only if all of the following criteria are met.

(a) All of the services to be totalized must be at the same voltage level

(b) The facility's total demand load must exceed the company's loading criteria for the largest standard transformer purchased by the company to serve that voltage level.

(c) The facility must be comprised of one building containing a single integrated business* operated by one Customer.

Totalized metering, when authorized by the Company, will normally be provided to a single geographical point. However, service may be provided at multiple geographical points if the Customer pays the company all costs associated with the additional facilities necessary to achieve these multiple service locations.

A customer operating a single integrated business under one name in two or more buildings and/or energy consuming locations may request a single point of delivery and such request shall be complied with by the Company providing that –

(1) such buildings or locations are situated on a single unit of property; or

(2) such buildings or locations are situated on two or more units of property which are immediately adjoining, adjacent or contiguous; or

(3) such buildings or locations are situated on two or more units of property which would be immediately adjoining, adjacent or contiguous except for intervening streets, alleys or highways;

and in all cases arising in sub-paragraphs (1), (2), or (3), it shall be the customer's responsibility to provide the electrical facilities necessary for distributing the energy beyond the single delivery point.

* The word "business" as used in this section shall be construed as including residences and educational, religious, governmental, commercial and industrial operations.

Continued to Sheet No. 5.080

Continued from Sheet No. 5.075

2.2.2 CONTINUITY OF SERVICE

The Company will use reasonable diligence at all times to provide continuous service at the agreed nominal voltage, and shall not be liable to the Customer for any damages arising from causes beyond its control or from the negligence of the Company, its employees, servants or agents, including, but not limited to, damages for complete or partial failure or interruption of service, for initiation of or re-connection of service, for shutdown for repairs or adjustments, for fluctuations in voltage, for delay in providing or in restoring service, or for failure to warn of interruption of service.

Whenever the Company deems that an emergency warrants interruption or limitation in the service supplied, or there is a delay in providing or restoring said service because of an emergency, such interruption, limitation or delay shall not constitute a breach of contract and shall not render the Company liable for damages suffered thereby or excuse the Customer from fulfillment of its obligations.

2.2.3 FORCE MAJEURE

The Company shall not be liable to the Customer, or to others for whose benefit this contract may be made, for any injury to persons or fatality, including the Customer, or for any damage to property, including property of the Customer, when such injury, fatality or damage is caused directly or indirectly by:

(1) a hurricane, storm, heat wave, lightning, freeze, severe weather event, or other act of God

(2) fire, explosion, war, riot, labor strike, or lockout, embargo, interference by federal, state or municipal governments, injunction or other legal process;

(3) breakage or failure of any property, facility, machinery, equipment or lines of the Company, the Customer, or others.

2.2.4 INDEMNITY TO COMPANY

The Customer shall indemnify, hold harmless and defend the Company from and against any and all liability, proceedings, suits, costs or expenses, including attorney's fees and costs, for loss or damage to property or for injury to persons or fatality, in any manner directly or indirectly connected with, or arising out of, the use of electricity on the Customer's side of the point of delivery or out of the Customer's negligent acts or omissions.

Continued to Sheet No. 5.081

TECO TAMPA ELECTRIC AN EMERA COMPANY

ORIGINAL SHEET NO. 5.081

Continued from Sheet No. 5.080

Governmental – Notwithstanding anything to the contrary in the Company's tariff, including these General Rules and Regulations for Electric Service, the Company's Rate Schedules and its Standard Forms, any obligation of indemnification therein required of a Customer that is a governmental entity of the State of Florida or political subdivision thereof ("governmental entity"), shall be read to include the condition "to the extent permitted by applicable law."

The Customer shall be responsible for any damage to or loss of Company's property located on Customer's premises, caused by or arising out of the acts, omissions or negligence of Customer or others, or the misuse or unauthorized use of Company's property by Customer or others. The cost of making good such loss and/or repairing such damage shall be paid by the Customer. Customer shall be held responsible for injury to Company's employees if caused by Customer's acts, omissions, or negligence.

The Customer shall be responsible for any injury to persons or damage to property occasioned or caused by the acts, omissions or negligence of the Customer or any of his agents, employees, or licensees, in installing, maintaining, operating, or using any of Customer's lines, wires, equipment, machinery, or apparatus, and for injury and damage caused by defects in the same.

The Company shall not be liable for any property damage, fatality, or personal injury sustained on the Customer's premises resulting from the Customer's Installation or the fittings, appliances, or apparatus of any type on Customer's premises. The Company will not be responsible for the use, care, or handling of electricity once the electricity passes the Delivery Point.

The Company shall not be held liable for injury to persons or damage to property caused by its lines or equipment when contacted, approached or interfered with by ladders, pipes, poles, guy wires, ropes, saws, aerial wires, painting equipment, aerial lifts, cranes, attachments, trees, structures, airplanes or other objects not the property of Company, which cross over, through, or are in close proximity to Company's lines and equipment, unless said lines and equipment are in a defective condition. Company should be given adequate written notice by the customer before trees overhanging or in close proximity to Company's lines or equipment are trimmed or removed or when stacks, guys, radio or television aerials, wires, ropes, drain pipes, poles, structures, or other objects are installed or removed near Company's lines or equipment or the customer plans any work in close proximity to the Company's overhead lines, but Company assumes no liability whatsoever because of such notice, unless a Company representative is present during such installation or removal

Continued to Sheet No. 5.090

Continued from Sheet No. 5.081

2.2.5 LIMITATION ON CONSEQUENTIAL DAMAGES

The Customer shall not be entitled to recover from the Company for loss of use of any property or equipment, loss of profits or income, loss of production, rental expenses for replacement of property or equipment, diminution in value of property, expenses to restore operations, loss of goods or products, or any other consequential, indirect, unforeseen, incidental or special damages.

2.3 COMPANY EQUIPMENT ON PRIVATE PROPERTY

An easement will be required where necessary for the Company to locate its facilities on property not designated as a public right-of-way. Service drops, service laterals and area light services are the exception to the preceding rule. If a service drop or service lateral is expected to serve future customers, an easement should be obtained. Easements will also be required where it is necessary for the Company's facilities to cross over property not designated as public right-of-way to serve customers other than the property owner. Normal distribution easements will be 15 feet wide, but easements will vary in dimensions depending upon the type of facility necessary. All matters pertaining to easements will be handled directly with the appropriate representative in the Company office serving the area in question.

In the event that the Company's facilities are located on a customer's property to serve the customer, and if it becomes desirable to relocate these facilities due to expansion of the customer's building or other facilities, or for other reasons initiated by the customer, the Company will, where feasible, relocate its facilities. The Company may require that all costs associated with the requested relocation or removal be charged to the customer making the request and may require an easement for the relocated facilities.

2.4 ELECTRIC SYSTEM RELOCATIONS

In subdivided property in general, the Company endeavors to locate its facilities such that they are in the immediate vicinity of a lot line. This may not be possible due to subdivision replatting or inability of the Company to so locate its facilities. In rural areas facilities are located so as to provide the most efficient electrical distribution system.

If a customer desires that a guy wire, pole or other facility be relocated, the Engineering Department at the nearest Company office should be contacted. Consideration will be given to each case; and if practicable, the Company will relocate such facility to the vicinity of the nearest lot line or to the desired location. The Company may require that all costs associated with the requested relocation or removal be charged to the customer making the request.

Continued to Sheet No. 5.100

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 5.105
CANCELS FOURTH REVISED SHEET NO. 5.105

Continued from Sheet No. 5.100

2.6.1 CONTRIBUTION IN AID OF CONSTRUCTION

The company recognizes its obligation to furnish electric service to customers throughout its entire service area, but necessarily must reserve the right to require a contribution in aid of construction (CIAC) when the additional distribution investment is not considered prudent. A CIAC will normally be required when the cost of the facilities required to serve a customer are in excess of those normally provided by the company. CIAC fees are intended to protect the general body of ratepayers from subsidizing special requests.

If the company considers the prospects of securing additional revenue from additional distribution investment to be favorable, (i.e. in public road right-of-way, other customers and/or additional load) such payment, or portion thereof, may be waived.

When a CIAC is required, the customer shall deposit with the company the specified amount prior to the company commencing construction (unless alternative acceptable payment arrangements are made). The company will install, own, and maintain the electrical distribution facilities up to the company designated point of delivery. Any payment by the customer under the provisions of this policy will not convey to the customer any rights of ownerships.

CIAC for the installation of new or upgraded overhead facilities ($CIAC_{OH}$) will be calculated as follows:

$CIAC_{OH}$	=	Total estimated work order job cost of installing the facilities	-	Four years expected incremental base energy charge revenue	-	Four years expected incremental base demand charge revenue

The cost of the service drop and meter shall be excluded in the total estimated work order job cost for new overhead facilities.

The net book value and cost of removal, net of the salvage value, for existing facilities shall be included in the total estimated work order job cost for upgrades to those existing facilities.

For projects that do not include line extensions associated with electric vehicle fast charger projects, investment allowance equal to four years expected annual base energy and demand charge revenue shall be estimated for a period not more than five (5) years after the new or upgraded facilities are placed in service. For line extensions associated with electric vehicle fast charger projects, the revenue estimate shall be for four (4) consecutive years within a period of not more than ten (10) years after the fast chargers are placed in service.

In no instance shall the $CIAC_{OH}$ be less than zero.

Continued to Sheet No. 5.106

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SEVENTH REVISED SHEET NO. 5.130
CANCELS SIXTH REVISED SHEET NO. 5.130

Continued from Sheet No. 5.120

2.12 DEPOSITS

At the company's option, a deposit amount of up to two (2) month's average billing, or a suitable guarantee as security for payment for electric service, may be required at any time. Initial deposits for new premises are calculated based on the customer's submission of electrical load information. This information is then utilized to estimate average monthly usage. Initial deposits for existing premises, where typical usage has registered in the past 6 months, is calculated by accessing historical usage. If such historical usage is not available, a load calculating tool is used to establish average usage based on square footage of dwelling. As a suitable guarantee the applicant for service may furnish either (1) a satisfactory guarantor to secure payment of bills for the service requested, (2) an irrevocable letter of credit from a bank, or (3) a surety bond. For residential customers, a satisfactory guarantor shall, at the minimum, be a customer with a satisfactory payment record. For non-residential customers, a satisfactory guarantor need not be a customer of the utility. Each utility shall develop minimum financial criteria that a proposed guarantor must meet to qualify as a satisfactory guarantor. A copy of the criteria shall be made available to each new non-residential customer upon request by the customer.

After a residential customer has established a satisfactory payment record and has had continuous service for a period of twenty-three (23) months, the customer's deposit shall be refunded provided the customer has not in the preceding twelve (12) months, (a) made more than one late payment of a bill (after the expiration of twenty (20) days from the date of mailing or delivery by the company), (b) paid with a check refused by a bank, (c) been disconnected for nonpayment, or at any time, (d) tampered with the electric meter, or (e) used service in a fraudulent or unauthorized manner.

A minimum of two percent (2%) interest per annum on deposits shall be credited to the current bill annually and when deposits are refunded. Interest of three percent (3%) shall be paid on deposits of non-residential customers after the deposits have been held for twenty-three (23) months and the company elects not to refund the deposits. The deposit interest shall be simple interest in all cases. No customer depositor shall be entitled to receive interest on his deposit until and unless the customer relationship and the deposit have been in existence for a continuous period of six (6) months, then he shall be entitled to receive interest from the day of the commencement of the customer relationship and the placement of deposit.

Upon termination of service, and provided all bills have been paid in full, the deposit and accrued interest may be credited against the final account and the balance if any, shall be returned promptly to the customer or agency within fifteen (15) days after service is discontinued.

Continued to Sheet No. 5.135

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTH REVISED SHEET NO. 5.180
CANCELS EIGHTH REVISED SHEET NO. 5.180

Continued from Sheet No. 5.175

Where the company's facilities are reasonably adequate and of sufficient capacity to carry the actual loads normally imposed, the company may require that the equipment on the Customer's premises shall be such that the starting and operating characteristics will not cause an instantaneous voltage drop of more than 4% of the standard voltage, measured at the point of delivery, or cause objectionable flicker to other Customer's service.

2.17 EMERGENCY RELAY POWER SUPPLY

The Company will receive applications for emergency relay power supply service from existing and/or new customers and reserves the right to approve or disapprove each application based upon need, location, feasibility, availability and size of load.

After receiving approval, the Company will require that all costs of any duplication of additional facilities required by the customer in excess of the facilities normally furnished by the Company for a single source, single transformation, electric service installation, be charged to the customer making the request. This shall include the cost of existing facilities being reserved at a charge of $62.51 per kW.

Customers requesting relay service through a single point of delivery to a multi-serviced facility, must ensure that all new occupants of the multi-serviced facility beyond the single point of delivery are aware of the obligation to pay charges associated with relay service. All existing occupants (i.e. occupants with leases predating the request for relay service to a multi-serviced facility) may choose not to pay the relay service charge at the time service is provided but must pay the charge upon renewal of the existing lease. Any unrecovered revenues related to the relay service charge will be billed to the customer requesting relay service for the multi-serviced facility.

Exceptions may be made by the Company when public safety is involved.

III. CUSTOMER SERVICES AND WIRING

3.1 GENERAL REQUIREMENTS FOR CUSTOMER WIRING

As previously stated, compliance of customer owned facilities with the requirements of the National Electrical Code will provide the customer with a safe installation, but not necessarily an efficient or convenient installation.

Continued to Sheet No. 5.181

Continued from Sheet No. 5.250

3) The customer may, at the option of Company, be required to provide a collector bus in the vault area. The collector and service bus shall be of weatherproof construction and/or include fused sections where deemed applicable by the Company.

4) Normally, customer metering will not be located in the vault area. In most cases Company metering instrument transformers furnished by the Company shall be installed by the customer. Details of metering instrument transformer installations shall be approved by the Company prior to switchgear construction.

5) Prior to bid and construction, the customer shall obtain from the Company a written statement to the effect that engineering design drawings of the vault structure, collector bus, conduit systems, service bus, service equipment, vault ventilation system and vault lighting prepared by the customer's architect and or engineer have been reviewed by the Company and meet at least the minimum Company requirements for such structures and equipment. Prior to fabrication, related shop drawings must also be submitted and a written statement obtained from the Company to the effect such structures and equipment meet at least the minimum Company requirements.

6) The customer shall install and maintain the necessary conduit system from the vault area to a point specified by the Company. This point will normally be two feet outside the property line into public right-of-way. The conduit system shall be designed and constructed to no less than the Company's minimum requirements.

7) The customer shall compensate the Company as a contribution in aid of construction for all primary cable required in excess of 150 feet from the property line to the vault.

8) An easement shall be required and executed for all transformer vaults and conduit systems on private property prior to service connection.

Continued to Sheet No. 5.270

Continued from Sheet No. 5.310

9) An easement shall be required and executed for all transformer vaults and conduit systems on private property prior to service connection.

10) The overall design for electric service shall be determined by the Company for the most desirable and economical system. The overall project should be considered in the planning stage for initial as well as ultimate load, number of buildings, and services required from the best planning information available to both the Company and the customer.

11) Transformer vault structures and conduit systems constructed by the customer shall remain the customer's property; however, the transformer vault and conduit system shall be under the operational jurisdiction of the Company. The Company shall have the right to connect the transformer vault electrically into its underground network system. The customer shall be responsible for maintenance of the vault structure and conduit system to the Company's satisfaction.

12) The Company shall furnish, connect and maintain all network transformers and network protectors. The Company shall also furnish, install and maintain all primary cable, network protector secondary leads, network secondary cable, street lighting cable, supervisory cable, the vault grounding system (exclusive of ground rods or grounding connection point), and sump pumps (where required).

The customer shall provide and install ground rods or a grounding connection point in the vault in accordance with no less than Company minimum requirements.

13) In the event the transformer vault is located in such a manner that it is necessary for walls, grating, ventilation louver systems or any structural improvements to be moved, removed, modified, or relocated during the installation, maintenance, removal and/or replacement of transformers and/or any other related equipment, then the customer shall be responsible at his expense to move, remove, modify, relocate and/or replace the walls, grating, ventilation louver systems or any structural improvements.

Continued to Sheet No. 5.330

RESERVED FOR FUTURE USE

TECO TAMPA ELECTRIC AN EMERA COMPANY

FIFTH REVISED SHEET NO. 6.025
CANCELS FOURTH REVISED SHEET NO. 6.025

CLEAN ENERGY TRANSITION MECHANISM

Rate Schedules		Energy Rate ¢/kWh
		Rates
RS (up to 1,000 kWH)		0.406
RS (over to 1,000 kWH)		0.406
RSVP-1	(P1)	0.406
	(P2)	0.406
	(P3)	0.406
	(P4)	0.406
GS, GST		0.418
CS		0.418
LS-1, LS-2		0.043
GSD Optional		
Secondary		0.272
Primary		0.272
Subtransmission		0.272

Rate Schedule	Billing Demand $/kW	Supplemental Demand $/kW	Standby Dem. LFRC $/kW	Standby Dem. PSRC Monthly $kW	Standby Dem. PSDC Daily $/kW
GSD, GSDT, SBD, SBDT					
Secondary	$1.15	$1.15	$1.15	$0.13	$0.05
Primary	$1.15	$1.15	$1.15	$0.13	$0.05
Subtransmission	$1.15	$1.15	$1.15	$0.13	$0.05
GSLDPR,GSLDTPR, SBLDPR, SBLDTPR Primary	$0.86	$0.86	$0.86	$0.10	$0.04
GSLDSU,GSLDTSU, SBLDSU,SBLDTSU, Subtransmission	$0.53	$0.53	$0.53	$0.07	$0.02

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-THIRD REVISED SHEET NO. 6.030
CANCELS THIRTY-SECOND REVISED SHEET NO. 6.030

RESIDENTIAL SERVICE

SCHEDULE: RS

AVAILABLE: Entire service area.

APPLICABLE: To residential consumers in individually metered private residences, apartment units, and duplex units. All energy must be for domestic purposes and should not be shared with or sold to others. In addition, energy used in commonly-owned facilities in condominium and cooperative apartment buildings will qualify for this rate schedule, subject to the following criteria:

1. 100% of the energy is used exclusively for the co-owners' benefit.
2. None of the energy is used in any endeavor which sells or rents a commodity or provides service for a fee.
3. Each point of delivery will be separately metered and billed.
4. A responsible legal entity is established as the customer to whom the Company can render its bills for said service.

Resale not permitted.

Billing charges shall be prorated for billing periods that are less than 25 days or greater than 35 days. If the billing period exceeds 35 days and the billing extension causes energy consumption, based on average daily usage, to exceed 1,000 kWh, the excess consumption will be charged at the lower monthly Energy and Demand Charge.

LIMITATION OF SERVICE: This schedule includes service to single phase motors rated up to 7.5 HP. Three phase service may be provided where available for motors rated 7.5 HP and over.

RATES:

Basic Service Charge:
$ 0.43 per day.

Energy and Demand Charge:

First 1,000 kWh	8.457 ¢ per kWh
All additional kWh	9.457 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

Continued to Sheet No. 6.031

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

ELEVENTH REVISED SHEET NO. 6.031
CANCELS TENTH REVISED SHEET NO. 6.031

Continued from Sheet No. 6.030

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-FOURTH REVISED SHEET NO. 6.050
CANCELS THIRTY-THIRD REVISED SHEET NO. 6.050

GENERAL SERVICE - NON DEMAND

SCHEDULE: GS

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted on Schedule GST only.

RATES:

Basic Service Charge:

Metered accounts	$0.63 per day
Un-metered accounts	$0.35 per day

Energy and Demand Charge:

8.217 ¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.243 ¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.051

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-THIRD REVISED SHEET NO. 6.051
CANCELS TWENTY-SECOND REVISED SHEET NO. 6.051

Continued from Sheet No. 6.050

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-THIRD REVISED SHEET NO. 6.080
CANCELS THIRTY-SECOND REVISED SHEET NO. 6.080

GENERAL SERVICE - DEMAND

SCHEDULE: GSD

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

STANDARD

Basic Service Charge:

Secondary Metering Voltage	$ 1.06 per day
Primary Metering Voltage	$11.54 per day
Subtrans. Metering Voltage	$35.23 per day

Demand Charge:
$18.07 per kW of billing demand

Energy Charge:
0.773 ¢ per kWh

OPTIONAL

Basic Service Charge:

Secondary Metering Voltage	$ 1.06 per day
Primary Metering Voltage	$11.54 per day
Subtrans. Metering Voltage	$35.23 per day

Demand Charge:
$0.00 per kW of billing demand

Energy Charge:
7.799 ¢ per kWh

The customer may select either standard or optional. Once an option is selected, the customer must remain on that option for twelve (12) consecutive months.

Continued to Sheet No. 6.081

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-EIGHTH REVISED SHEET NO. 6.081
CANCELS TWENTY-SEVENTH REVISED SHEET NO. 6.081

Continued from Sheet No. 6.080

BILLING DEMAND: The highest measured 30-minute interval kW demand during the billing period.

MINIMUM CHARGE: The Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When a customer under the standard rate takes service at primary voltage, a discount of $1.35 per kW of billing demand will apply. A discount of $5.59 per kW of billing demand will apply when a customer under the standard rate takes service at subtransmission or higher voltage.

When a customer under the optional rate takes service at primary voltage, a discount of 0.346¢ per kWh will apply. A discount of 1.431¢ per kWh will apply when a customer under the optional rate takes service at subtransmission or higher voltage.

Continued to Sheet No. 6.082

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SIXTEENTH REVISED SHEET NO. 6.082
CANCELS FIFTEENTH REVISED SHEET NO. 6.082

Continued from Sheet No. 6.081

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of billing demand for customers taking service under the standard rate and 0.243¢/kWh for customer taking service under the optional rate. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.140
CANCELS THIRTEENTH REVISED SHEET NO. 6.140

GENERAL SERVICE - LARGE DEMAND PRIMARY

SCHEDULE: GSLDPR

AVAILABLE: Entire Service Area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $ 20.89 per day

Demand Charge: $ 13.41 per kW of billing demand

Energy Charge: 1.105¢ per kWh

Continued to Sheet No. 6.145

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.145
CANCELS SECOND REVISED SHEET NO. 6.145

Continued from Sheet No. 6.140

BILLING DEMAND: The highest measured 30-minute interval kW demand during the month.

MINIMUM CHARGE: The Daily Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Power Factor billing and Emergency Relay Power Supply Charge.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of registered demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Nos. 6.020 and 6.022

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.160
CANCELS THIRD REVISED SHEET NO. 6.160

GENERAL SERVICE - LARGE DEMAND SUBTRANSMISSION

SCHEDULE: GSLDSU

AVAILABLE: Entire Service Area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSD. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for the purposes of administering this requirement. Resale not permitted

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase, at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $ 126.72 a day

Demand Charge: $ 12.16 per kW of billing demand

Energy Charge: 1.163¢ per kWh

Continued to Sheet No. 6.165

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.165
CANCELS SECOND REVISED SHEET NO. 6.165

Continued from Sheet No. 6.160

BILLING DEMAND: The highest measured 30-minute interval kW demand during the month.

MINIMUM CHARGE: The Daily Basic Service Charge and any Minimum Charge associated with optional riders.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of registered demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

CONSTRUCTION SERVICE

SCHEDULE: CS

AVAILABLE: Entire service area.

APPLICABLE: Single phase temporary service used primarily for construction purposes.

LIMITATION OF SERVICE: Service is limited to construction poles and services installed under the TUG program. Construction poles are limited to a maximum of 70 amperes at 240 volts for construction poles. Larger (non-TUG) services and three phase service entrances must be served under the appropriate rate schedule, plus the cost of installing and removing the temporary facilities is required.

RATES:
Basic Service Charge: $0.63 per day

Energy and Demand Charge: 8.217¢ per kWh

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

Continued from Sheet No. 6.290

MISCELLANEOUS: A Temporary Service Charge of $480.00 shall be paid upon application for the recovery of costs associated with providing, installing, and removing the company's temporary service facilities for construction poles. Where the Company is required to provide additional facilities other than a service drop or connection point to the Company's existing distribution system, the customer shall also pay, in advance, for the estimated cost of providing, installing and removing such additional facilities, excluding the cost of any portion of these facilities which will remain as a part of the permanent service.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-THIRD REVISED SHEET NO. 6.320
CANCELS THIRTY-SECOND REVISED SHEET NO. 6.320

TIME-OF-DAY
GENERAL SERVICE - NON DEMAND
(OPTIONAL)

SCHEDULE: GST

AVAILABLE: Entire service area.

APPLICABLE: For lighting and power in establishments not classified as residential whose energy consumption has not exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. All of the electric load requirements on the customer's premises must be metered at one (1) point of delivery. For any billing period that exceeds 35 days, the energy consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: Single or 3 phase, 60 cycles and approximately 120 volts or higher, at Company's option.

LIMITATION OF SERVICE: All service under this rate shall be furnished through one meter. Standby service permitted.

RATES:

Basic Service Charge:
$0.63 per day

Energy and Demand Charge:
12.873¢ per kWh during peak hours
6.617¢ per kWh during off-peak hours

Continued to Sheet No. 6.321

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-SIXTH REVISED SHEET NO. 6.321
CANCELS TWENTY-FIFTH REVISED SHEET NO. 6.321

Continued from Sheet No. 6.320

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

MINIMUM CHARGE: The Basic Service Charge.

TERMS OF SERVICE: A customer electing this optional rate shall have the right to transfer to the standard applicable rate at any time without additional charge for such transaction, except that any customer who requests this optional rate for the second time on the same premises will be required to sign a contract to remain on this rate for at least one (1) year.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 0.243 ¢ per kWh of billing energy. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

Continued to Sheet No. 6.322

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIFTH REVISED SHEET NO. 6.322
CANCELS FOURTH REVISED SHEET NO. 6.322

Continued from Sheet No. 6.321

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRTY-FOURTH REVISED SHEET NO. 6.330
CANCELS THIRTY-THIRD REVISED SHEET NO. 6.330

TIME-OF-DAY
GENERAL SERVICE - DEMAND
(OPTIONAL)

SCHEDULE: GSDT

AVAILABLE: Entire service area.

APPLICABLE: To any customer whose energy consumption has exceeded 9,000 kWh in any one of the prior twelve (12) consecutive billing periods ending with the current billing period. Also available to customers with energy consumption at any level below 9,000 kWh per billing period who agree to remain on this rate for at least twelve (12) months. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard Company voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Basic Service Charge:

Secondary Metering Voltage	$ 1.06 per day
Primary Metering Voltage	$11.54 per day
Subtransmission Metering Voltage	$35.23 per day

Demand Charge:
$ 6.38 per kW of billing demand, plus
$11.70 per kW of peak billing demand

Energy Charge:
1.253¢ per kWh during peak hours
0.600¢ per kWh during off-peak hours

Continued to Sheet No. 6.331

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-EIGHTH REVISED SHEET NO. 6.332
CANCELS TWENTY-SEVENTH REVISED SHEET NO. 6.332

Continued from Sheet No. 6.331

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage a discount of $1.35 per kW of billing demand will apply. When the customer takes service at subtransmission or higher voltage, a discount of $5.59 per kW of billing demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTEENTH REVISED SHEET NO. 6.370
CANCELS THIRTEENTH REVISED SHEET NO. 6.370

TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
PRIMARY
(OPTIONAL)

SCHEDULE: GSLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $20.89 a day

Demand Charge:
$3.93 per kW of billing demand, plus
$9.49 per kW of peak billing demand

Energy Charge:
1.679¢ per kWh during peak hours
0.898¢ per kWh during off-peak hours

Continued to Sheet No. 6.375

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.380
CANCELS SECOND REVISED SHEET NO. 6.380

Continued from Sheet No. 6.375

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission voltage or higher, a discount of 1% will apply to the Demand Charge, Energy Charge, Power Factor Billing and Emergency Relay Power Supply Charge.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.400
CANCELS NINTH REVISED SHEET NO. 6.400

TIME-OF-DAY
GENERAL SERVICE LARGE - DEMAND
SUBTRANSMISSION
(OPTIONAL)

SCHEDULE: GSLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Once a customer has gone (12) consecutive months of less than 1000 kW registered demand the customer will then be billed under the rate schedule GSDT. For any billing period that exceeds 35 days, the consumption shall be prorated to that of a 30-day amount for purposes of administering this requirement. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: Standby service is permitted only for customers who generate less than 20% of their on-site load requirements or whose generating equipment is used for emergency purposes.

RATES:

Daily Basic Service Charge: $126.72 a day

Demand Charge:
$1.53 per kW of billing demand, plus
$10.63 per kW of peak billing demand

Energy Charge:
1.400¢ per kWh during peak hours
1.089¢ per kWh during off-peak hours

Continued to Sheet No. 6.405

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.410
CANCELS SECOND REVISED SHEET NO. 6.410

Continued from Sheet No. 6.405

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of billing demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTIETH REVISED SHEET NO. 6.565
CANCELS NINETEENTH REVISED SHEET NO. 6.565

Continued from Sheet No. 6.560

RATES:
Basic Service Charge: $0.43 per day

Energy and Demand Charges: 8.917¢ per kWh (for all pricing periods)

MINIMUM CHARGE: The Basic Service Charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023. .

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

Continued to Sheet No. 6.570

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.600
CANCELS TWENTIETH REVISED SHEET NO. 6.600

STANDBY AND SUPPLEMENTAL SERVICE
DEMAND

SCHEDULE: SBD

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.06
Primary Metering Voltage	$ 11.54
Subtransmission Metering Voltage	$ 35.23

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 3.81 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 2.17 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.86 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.900 ¢ per Standby kWh

Continued to Sheet No. 6.601

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FOURTH REVISED SHEET NO. 6.601
CANCELS TWENTY-THIRD REVISED SHEET NO. 6.601

Continued from Sheet No. 6.600

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:

$ 18.07	per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:

0.773¢	per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units:

Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.602

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FOURTH REVISED SHEET NO. 6.603
CANCELS TWENTY-THIRD REVISED SHEET NO. 6.603

Continued from Sheet No. 6.602

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charge, Energy Charge, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of $1.35 per kW of Supplemental Demand and $3.42 per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $5.59 per kW of Supplemental Demand and $4.54 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBD. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBD .

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

EIGHTEENTH REVISED SHEET NO. 6.605
CANCELS SEVENTEETH REVISED SHEET NO. 6.605

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL DEMAND SERVICE
(OPTIONAL)

SCHEDULE: SBDT

AVAILABLE: Entire service area.

APPLICABLE: To all secondary voltage served customers. Also to primary and subtransmission served customers with a registered demand of 999 kW or below in all of the last 12 months. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take firm service from the utility. Also available to applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at any standard company voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge:

Secondary Metering Voltage	$ 1.06
Primary Metering Voltage	$ 11.54
Subtransmission Metering Voltage	$ 35.23

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$3.81 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$2.17 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.86 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.900¢ per Standby kWh

Continued to Sheet No. 6.606

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWENTY-FIRST REVISED SHEET NO. 6.606
CANCELS TWENTIETH REVISED SHEET NO. 6.606

Continued from Sheet No. 6.605

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$6.38	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$11.70	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.253¢	per Supplemental kWh during peak hours
0.600¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Continued to Sheet No. 6.607

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO TAMPA ELECTRIC AN EMERA COMPANY

TWENTIETH REVISED SHEET NO. 6.608
CANCELS NINETEENTH REVISED SHEET NO. 6.608

Continued from Sheet No. 6.607

TERM OF SERVICE: Any customer receiving service under this schedule will be required to give the Company written notice at least 60 months prior to transferring to a non-standby schedule. Such notice shall be irrevocable unless the Company and the customer should mutually agree to void the notice.

TEMPORARY DISCONTINUANCE OF SERVICE: Where the use of energy is seasonal or intermittent, no adjustments will be made for a temporary discontinuance of service. Any customer prior to resuming service within 12 months after such service was discontinued will be required to pay all charges which would have been billed if service had not been discontinued.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at primary voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

When the customer takes energy metered at subtransmission or higher voltage, a discount of 2% will apply to the Demand Charges, Energy Charges, Delivery Voltage Credit, Power Factor billing, and Emergency Relay Power Supply Charge.

DELIVERY VOLTAGE CREDIT: When the customer takes service at primary voltage, a discount of $1.35 per kW of Supplemental Demand and $3.42 per kW of Standby Demand will apply.

When the customer takes service at subtransmission or higher voltage, a discount of $5.59 per kW of Supplemental Demand and $4.54 per kW of Standby Demand will apply.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

Continued to Sheet No. 6.609

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.609
CANCELS THIRD REVISED SHEET NO. 6.609

Continued from Sheet No. 6.608

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TWELFTH REVISED SHEET NO. 6.610
CANCELS ELEVENTH REVISED SHEET NO. 6.610

STANDBY- LARGE - DEMAND
PRIMARY

SCHEDULE: SBLDPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Basic Service Charge: $21.71 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$2.84 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:
$1.61 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$0.64 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.908¢ per Standby kWh

Continued to Sheet No. 6.615

TECO. TAMPA ELECTRIC AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.615
CANCELS THIRD REVISED SHEET NO. 6.615

Continued from Sheet No. 6.610

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 13.41 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.105¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during a 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.620

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

TENTH REVISED SHEET NO. 6.625
CANCELS NINTH REVISED SHEET NO. 6.625

Continued from Sheet No. 6.625

POWER FACTOR: Power factor will be calculated for customers with measured demands of 1,000 kW in any billing period out of twelve (12) consecutive billing periods ending with the current billing period. When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the Demand Charge, Energy Charge, Power Factor Billing and Emergency Relay Power Supply Charge.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBLDPR. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBLDPR.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.630
CANCELS THIRD REVISED SHEET NO. 6.630

STANDBY-LARGE DEMAND SUBTRANSMISSION

SCHEDULE: SBLDSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Firm Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $127.55 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$1.31 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$1.47 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$0.58 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.866¢ per Standby kWh

Continued to Sheet No. 6.635

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.635
CANCELS THIRD REVISED SHEET NO. 6.635

Continued from Sheet No. 6.630

CHARGES FOR SUPPLEMENTAL SERVICE:

Demand Charge:
$ 12.16 per kW-Month of Supplemental Billing Demand (Supplemental Billing Demand Charge)

Energy Charge:
1.163¢ per Supplemental kWh

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the company during the month.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the Company, occurring in the same 30-minute interval, during the month.

Normal Generation - The generation level equaled or exceeded by the Customer's generation 10% of the metered intervals during the previous twelve months.

Supplemental Billing Demand - The amount, if any, by which the highest Site Load during any 30-minute interval in the month exceeds Normal Generation, but no greater than Metered Demand.

Continued to Sheet No. 6.640

TECO TAMPA ELECTRIC AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.645
CANCELS SECOND REVISED SHEET NO. 6.645

Continued from Sheet No. 6.640

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022. Note: Standby fuel charges shall be based on the time of use (i.e., peak and off-peak) fuel rates for Rate Schedule SBLDSU. Supplemental fuel charges shall be based on the standard fuel rate for Rate Schedule SBLDSU.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.650
CANCELS THIRD REVISED SHEET NO. 6.650

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
PRIMARY
(OPTIONAL)

SCHEDULE: SBLDTPR

AVAILABLE: Entire service area.

APPLICABLE: To all primary voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the primary voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at primary voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $21.71 a day

CHARGES FOR STANDBY SERVICE:

Demand Charge:
$2.84 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)
plus the greater of:
$1.61 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or
$0.64 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:
0.908¢ per Standby kWh

Continued to Sheet No. 6.655

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

Continued from Sheet No. 6.650

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$ 3.93	per kW-Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$ 9.49	per kW-Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.679¢	per Supplemental kWh during peak hours
0.898¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units:

Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.660

TECO TAMPA ELECTRIC AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.665
CANCELS SECOND REVISED SHEET NO. 6.665

Continued from Sheet No. 6.660

METERING VOLTAGE ADJUSTMENT: When the customer takes energy metered at subtransmission or higher voltage, a discount of 1% will apply to the Demand Charges, Energy Charges, Power Factor Billing and Emergency Relay Power Supply Charge.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.670
CANCELS THIRD REVISED SHEET NO. 6.670

TIME-OF-DAY
STANDBY AND SUPPLEMENTAL SERVICE
LARGE-DEMAND
SUBTRANSMISSION
(OPTIONAL)

SCHEDULE: SBLDTSU

AVAILABLE: Entire service area.

APPLICABLE: To all subtransmission voltage served customers with a registered demand of 1000 kW or above once in the last 12 months. Customer must take service at the subtransmission voltage level. Required for all applicable self-generating Customers whose generating capacity in kilowatts (exclusive of emergency generation equipment) exceeds 20% of their site load in kilowatts and who take service from the utility. Also available to all applicable self-generating Customers whose generating capacity in kilowatts does not exceed 20% of their site load in kilowatts, but who agree to all the terms and conditions of this rate schedule. Resale not permitted.

CHARACTER OF SERVICE: A-C; 60 cycles; 3 phase; at subtransmission voltage.

LIMITATION OF SERVICE: A Customer taking service under this tariff must sign a Tariff Agreement for the Purchase of Standby and Supplemental Service. (See Sheet No. 7.600)

RATES:

Daily Basic Service Charge: $ 127.55 per day

CHARGES FOR STANDBY SERVICE:

Demand Charge:

$ 1.31 per kW/Month of Standby Demand
(Local Facilities Reservation Charge)

plus the greater of:

$ 1.47 per kW/Month of Standby Demand
(Power Supply Reservation Charge) or

$ 0.58 per kW/Day of Actual Standby Billing Demand
(Power Supply Demand Charge)

Energy Charge:

0.866¢ per Standby kWh

Continued to Sheet No. 6.675

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FOURTH REVISED SHEET NO. 6.675
CANCELS THIRD REVISED SHEET NO. 6.675

Continued from Sheet No. 6.670

CHARGES FOR SUPPLEMENTAL SERVICE

Demand Charge:

$1.53	per kW/Month of Supplemental Demand (Supplemental Billing Demand Charge), plus
$10.63	per kW/Month of Supplemental Peak Demand (Supplemental Peak Billing Demand Charge)

Energy Charge:

1.400¢	per Supplemental kWh during peak hours
1.089¢	per Supplemental kWh during off-peak hours

DEFINITIONS OF THE USE PERIODS: All time periods stated in clock time. (Meters are programmed to automatically adjust for changes from standard to daylight saving time and vice-versa.)

	April 1 - October 31	November 1 - March 31
Peak Hours: (Monday-Friday)	12:00 Noon - 9:00 PM	6:00 AM - 10:00 AM and 6:00 PM - 10:00 PM

Off-Peak Hours: All other weekday hours, and all hours on Saturdays, Sundays, New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day shall be off-peak.

BILLING UNITS:

Demand Units: Metered Demand - The highest measured 30-minute interval kW demand served by the Company during the month.

Metered Peak Demand - The highest measured 30-minute interval kW demand served by the Company during the peak hours.

Site Load - The highest kW total of Customer generation plus deliveries by the company less deliveries to the company, occurring in the same 30-minute interval, during the month.

Peak Site Load - The highest 30-minute customer generation plus deliveries by the Company less deliveries to the Company during the peak hours.

Normal Generation - The generation level equaled or exceeded by the customer's generation 10% of the metered intervals during the previous twelve months.

Continued to Sheet No. 6.680

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.685
CANCELS SECOND REVISED SHEET NO. 6.685

Continued from Sheet No. 6.680

EMERGENCY RELAY POWER SUPPLY CHARGE: The monthly charge for emergency relay power supply service shall be 96¢ per kW of Supplemental Demand and Standby Demand. This charge is in addition to the compensation the customer must make to the Company as a contribution-in-aid of construction.

POWER FACTOR: When the average power factor during the month is less than 85%, the monthly bill will be increased 0.203¢ for each kVARh by which the reactive energy numerically exceeds 0.619744 times the billing energy. When the average power factor during the month is greater than 90%, the monthly bill will be decreased 0.102¢ for each kVARh by which the reactive energy is numerically less than 0.484322 times the billing energy.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE CHARGE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.720
CANCELS SECOND SHEET NO. 6.720

ECONOMIC DEVELOPMENT RIDER - EDR

SCHEDULE: EDR

AVAILABLE: Entire service area.

This Rider is available for non-residential load associated with initial permanent service to new establishments or the expansion of existing establishments. Service under the Rider is limited to Customers who make application to the Company for service under this Rider, and for whom the Company approves such application

APPLICABLE:

To participate in this rider, the customer must meet the following criteria:

1. Minimum qualifying load of 300 kW
   a. At a new or existing premise served by the Company that has been unoccupied or dormant, with minimal or no electric usage for the past 90 days.
2. The new or expanding business must also meet at least one of the following two requirements at the project location:
   a. The addition of 20 net new full time equivalent (FTE) jobs in the Company's service area; or
   b. Capital investment of $500,000 or greater and a new increase in FTE jobs in the Company's service area.
3. The Customer must provide written documentation attesting that the availability of this Rider is a significant factor in the customer's decision to locate or expand their business within the Company's service area.

Initial application for this Rider is not available to existing load. However, if a change in ownership occurs after the Customer contracts for service under this Rider, the successor Customer may be allowed to fulfill the balance of the contract under the Rider and continue the schedule of credits outlined below. This Rider is also not available for renewal of service following interruptions such as equipment failure, temporary plant shutdown, strike, or economic conditions. This Rider is also not available for load shifted from one establishment or delivery point on the Tampa Electric system to another on the Tampa Electric system.

The Customer Service Agreement under this Rider must include a description of the amount and nature of the load being provided, the number of FTE's resulting, and documentation verifying that the availability of the Economic Development Rider is a significant factor in the Customer's location/expansion decision.

Continued to Sheet No. 6.725

TECO TAMPA ELECTRIC AN EMERA COMPANY

THIRD REVISED SHEET NO. 6.725
CANCELS SECOND REVISED SHEET NO. 6.725

Continued from Sheet No. 6.720

LIMITATION OF SERVICE: The Company reserves the right to limit applications for this Rider when the Company's Economic Development expenses from this Rider and other sources exceed the amount set for the Company under Rule 25-6.0426 FAC.

Service under this Rider may not be combined with service under the Commercial/Industrial Service Rider.

DEFINITION: New Load: New Load is that which is added to the Company's system by a new establishment. For existing establishments, New Load is the net incremental load above that which existed prior to approval for service under this Rider.

DESCRIPTION: A credit based on the percentages below will be applied to the base demand charges and base energy charges of the Customer's otherwise applicable rate schedule associated with the Customer's New Load:

Year 1 – 20% reduction in base demand and energy charges*
Year 2 – 15% "
Year 3 – 10% "
Year 4 – 5% "
Year 5 – 0% "

*All other charges including basic service, fuel cost recovery, capacity cost recovery, conservation cost recovery, environmental cost recovery, storm protection plan cost recovery, and clean energy transition mechanism recovery will also be based on the Customer's otherwise applicable rate. The otherwise applicable rates may be any of the following: GSD, GSDT, GSLDPR, GSLDSU, GSLDTPR or GSLDTSU. Any Customer taking service under the CISR Rider is ineligible to take service under this EDR Rider.

The credit will begin once the Customer has achieved the minimum load and job requirements.

TERM OF SERVICE: The Customer agrees to a five-year contract term. Service under this Rider will terminate at the end of the fifth year. The customer may request an effective date of this Rider which is no later than two (2) years after the Customer Service Agreement is approved and signed by the Company.

The Company may terminate service under this Rider at any time if the Customer fails to comply with the terms and conditions of this Rider. Failure to: 1) maintain the level of employment specified in the Customer's Service Agreement and/or 2) purchase from the Company the amount of load specified in the Customer's Service Agreement may be considered grounds for termination.

PROVISIONS FOR EARLY TERMINATION: If the Company terminates service under this Rider for the Customer's failure to comply with its provisions, the Customer will be required to reimburse the Company for any discounts received under this Rider plus interest.

Continued to Sheet No. 6.730

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

SECOND REVISED SHEET NO. 6.730
CANCELS FIRST REVISED SHEET NO. 6.730

Continued from Sheet No. 6.725

If the Customer opts to terminate service under this Rider before the term of service specified in the Service Agreement the Customer will be required to reimburse the Company for any discounts received under this Rider plus interest.

The Service Agreement will automatically terminate if the minimum load and job requirements has not been achieved within 120 days of the effective date of the Service Agreement.

RULES AND REGULATIONS: Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service" the provision of this schedule shall apply.

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

ELEVENTH REVISED SHEET NO. 6.809
CANCELS TENTH REVISED SHEET NO. 6.809

Continued from Sheet No. 6.808

MONTHLY RATE:

LED Fixture, Maintenance, and Base Energy Charges:

Rate Code			Size				Charges per Unit ($)			
					kWh[1]				Base Energy[3]	
Dusk to Dawn	Timed Svc.	Description	Initial Lumens[1]	Lamp Wattage[2]	Dusk to Dawn	Timed Svc.	Fixture	Maint.	Dusk to Dawn	Timed Svc.
912	981	Roadway	2,600	27	9	5	7.72	1.74	0.29	0.16
914	901	Roadway	5,392	47	16	8	7.64	1.74	0.52	0.26
921	902	Roadway/Area	8,500	88	31	15	11.82	1.74	1.01	0.49
926	982	Roadway	12,414	105	37	18	10.85	1.19	1.21	0.59
932	903	Roadway/Area	15,742	133	47	23	20.41	1.38	1.53	0.75
935	904	Area-Lighter	16,113	143	50	25	15.21	1.41	1.63	0.82
937	905	Roadway	16,251	145	51	26	11.57	2.26	1.66	0.85
941	983	Roadway	22,233	182	64	32	14.74	2.51	2.09	1.04
945	906	Area-Lighter	29,533	247	86	43	21.20	2.51	2.80	1.40
947	984	Area-Lighter	33,600	330	116	58	26.60	1.55	3.78	1.89
951	985	Flood	23,067	199	70	35	16.51	3.45	2.28	1.14
953	986	Flood	33,113	255	89	45	27.78	4.10	2.90	1.47
956	987	Mongoose	23,563	225	79	39	17.77	3.04	2.58	1.27
958	907	Mongoose	34,937	333	117	58	22.22	3.60	3.81	1.89
965	991	Granville Post Top (PT)	3,024	26	9	4	8.47	2.28	0.29	0.13
967	988	Granville PT	4,990	39	14	7	18.50	2.28	0.46	0.23
968	989	Granville PT Enh[4]	4,476	39	14	7	22.10	2.28	0.46	0.23
971	992	Salem PT	5,240	55	19	9	15.07	1.54	0.62	0.29
972	993	Granville PT	7,076	60	21	10	20.24	2.28	0.68	0.33
973	994	Granville PT Enh[4]	6,347	60	21	10	23.76	2.28	0.68	0.33
975	990	Salem PT	7,188	76	27	13	19.57	1.54	0.88	0.42

[1] Average
[2] Average wattage. Actual wattage may vary by up to +/- 25 %.
[3] The Base Energy charges are calculated by multiplying the kWh times the lighting base energy rate of 3.260¢ per kWh for each fixture.
[4] Enhanced Post Top. Customizable decorative options

Continued to Sheet No. 6.810

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO TAMPA ELECTRIC AN EMERA COMPANY

SEVENTEENTH REVISED SHEET NO. 6.815
CANCELS SIXTEENTH REVISED SHEET NO. 6.815

Continued from Sheet No. 6.810

Miscellaneous Facilities Charges:

Rate Code	Description	Monthly Facility Charge	Monthly Maintenance Charge
563	Timer	$8.39	$1.43
569	PT Bracket (accommodates two post top fixtures)	$4.75	$0.06

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

MINIMUM CHARGE: The monthly charge.

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023

FRANCHISE FEE: See Sheet No. 6.023

PAYMENT OF BILLS: See Sheet No. 6.023

STORM PROTECTION PLAN RECOVERY PLAN: See Sheet Nos. 6.021 and 6.023

SPECIAL CONDITIONS:
On customer-owned public street and highway lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 3.260¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020. 6.021, 6.022 and 6.023.

Continued to Sheet No. 6.820

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

NINTH REVISED SHEET NO. 6.830
CANCELS EIGHTH REVISED SHEET NO. 6.830

CUSTOMER SPECIFIED LIGHTING SERVICE

SCHEDULE: LS-2

AVAILABLE: Entire service area

APPLICABLE:

Customer Specified Lighting Service is applicable to any customer for the sole purpose of lighting roadways or other outdoor areas. Service hereunder is provided for the sole and exclusive benefit of the customer, and nothing herein or in the contract executed hereunder is intended to benefit any third party or to impose any obligation on the Company to any such third party. At the Company's option, a deposit amount of up to a two (2) month's average bill may be required at anytime.

CHARACTER OF SERVICE:

Service is provided during the hours of darkness normally on a dusk-to-dawn basis. At the Company's option and at the customer's request, the company may permit a timer to control a lighting system provided under this rate schedule that is not used for dedicated street or highway lighting. The Company shall install and maintain the timer at the customer's expense. The Company shall program the timer to the customer's specifications as long as such service does not exceed 2,100 hours each year. Access to the timer is restricted to company personnel.

LIMITATION OF SERVICE:

Installation shall be made only when, in the judgment of the Company, location of the proposed lights are, and will continue to be, feasible and accessible to Company personnel and equipment for both construction and maintenance and such installation is not appropriate as a public offering under LS-1.

TERM OF SERVICE:

Service under this rate schedule shall, at the option of the company, begin on the date one or more of the lighting equipment is installed, energized, and ready for use and shall continue after the initial term for successive one-year terms until terminated by either party upon providing ninety (90) days prior written notice. Any customer transferring service to the LS-2 rate schedule from the LS-1 rate schedule shall continue the remaining primary initial term from LS-1 agreement.

SPECIAL CONDITIONS:

On lighting systems not subject to other rate schedules, the monthly rate for energy served at primary or secondary voltage, at the company's option, shall be 3.260¢ per kWh of metered usage, plus a Basic Service Charge of $ 0.71 per day and the applicable additional charges as specified on Sheet Nos. 6.020, 6.021, 6.022 and 6.023

Continued to Sheet No. 6.835

ISSUED BY: A. D. Collins, President

DATE EFFECTIVE:

Continued from Sheet No. 6.830

MONTHLY RATE: The monthly charge shall be calculated by applying the corresponding LS-2 Monthly Rental Factor set forth in Tariff Sheet No. 6.845 to the In-Place Value of the customer specific lighting facilities identified in the Outdoor Lighting Agreement entered into between the customer and the Company for service under this schedule.

The In-Place Value may change over time as new lights are added to the service provided under this Rate Schedule to a customer taking service, the monthly rate shall be applied to the In-Place Value in effect that billing month. The In-Place Value of any transferred LS-1 service shall be defined by the value of the lighting Equipment or its LED equivalent based on the average cost of a current installation. The in-Place Value of any new LS-2 service shall be defined by the value of the lighting equipment when it was first put in service.

NON-STANDARD FACILITIES AND SERVICES:
The customer shall pay all costs associated with additional company facilities and services that are not considered standard for providing lighting service, including but not limited to, the following:

1. relays;
2. distribution transformers installed solely for lighting service;
3. protective shields, bird deterrent devices, light trespass shields;
4. light rotations;
5. light pole relocations;
6. devices required by local regulations to control the levels or duration of illumination including associated planning and engineering costs;
7. removal and replacement of pavement required to install underground lighting equipment;
8. directional boring;
9. ground penetrating radar (GPR);
10. specialized permitting that is incremental to a standard construction permit;
11. specialized design and engineering scope required by either the customer or by local code or ordinance that is unique to the requested work;
12. custom maintenance of traffic permits;
13. removal of non-standard pole bases; and
14. blocked parking spaces resulting from construction or removal.

Payment may be made in a lump sum at the time the agreement is entered into, or at the customer's option these non-standard costs may be included in the In-Place Value to which the monthly rate will be applied.

MINIMUM CHARGE: The monthly charge.

ENERGY CHARGE: For monthly energy served under this rate schedule, 3.260¢ per kWh.

Continued to Sheet No. 6.840

TECO
TAMPA ELECTRIC
AN EMERA COMPANY

FIRST REVISED SHEET NO. 6.840
CANCELS ORIGINAL SHEET NO. 6.840

Continued from Sheet No. 6.835

FUEL CHARGE: See Sheet Nos. 6.020 and 6.022.

ENERGY CONSERVATION RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.022.

CAPACITY RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

CLEAN ENERGY TRANSITION MECHANISM: See Sheet Nos. 6.023 and 6.025.

ENVIRONMENTAL RECOVERY CHARGE: See Sheet Nos. 6.020 and 6.022.

FLORIDA GROSS RECEIPTS TAX: See Sheet No. 6.023.

FRANCHISE FEE: See Sheet No. 6.023.

PAYMENT OF BILLS: See Sheet No. 6.023.

STORM PROTECTION PLAN RECOVERY CHARGE: See Sheet Nos. 6.021 and 6.023.

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Continued from Sheet No. 6.840

LS-2 Monthly Rental Factors

Term Years	Factor
1	10.38%
2	5.37%
3	3.70%
4	2.87%
5	2.37%
6	2.04%
7	1.81%
8	1.63%
9	1.50%
10	1.39%
11	1.31%
12	1.23%
13	1.17%
14	1.12%
15	1.08%
16	1.04%
17	1.01%
18	0.98%
19	0.95%
20	0.93%
21	0.91%
22	0.89%
23	0.88%
24	0.86%
25	0.85%

Continued from Sheet No. 7.220

5. **Non-Standard Service Charges**
The Customer shall pay all costs associated with any additional Company facilities and services that are not considered standard for providing lighting service including, but not limited to: installation of distribution transformers, relays, protective shields, bird deterrent devices, light trespass shields, any devices required by local regulations to control the level or duration of illumination including any associated planning and engineering costs, removal and replacement of pavement required to install underground lighting cable, and directional boring. Charges will also be assessed for light rotations and light pole relocations. The Company will bill the Customer the actual cost of such nonstandard facilities and services as incurred.

6. **Customer Contribution in Aid of Construction**
The Company shall pay for all normal Equipment installation costs, with the exception of the following: $______ for_____. Refer to Section 5.2.6.1 of the Tampa Electric Tariff.

7. **Monthly Payment**
During the term of this Agreement, the Customer shall pay the Company monthly for the lighting services provided pursuant to Rate Schedule ______ as the rate schedule, which is on file with the Florida Public Service Commission, may be amended from time to time. All bills shall be due when rendered.

The current monthly base charges for “Equipment” installed under this agreement are______. Fuel and other adjustment clause charges and (where applicable) franchise fees and taxes per month under current tax rates pursuant to the Rate Schedule shall be_____. The total monthly charge shall be _____ per month.

Continued to Sheet No. 7.230

Continued from Sheet No. 7.225

The monthly charges specified in this agreement are tied to the tariff charges currently on file with the Florida Public Service Commission and may change during the term of this Agreement in accordance with filed changes to the relevant tariffs.

8. Term
This Agreement shall be effective on the later of the dates indicated on the signature block ("Effective Date") and shall continue on a month-to-month term (the "Term") as provided in the Rate Schedule _____, beginning on the date one or more of the Equipment is installed, and if applicable, at least one light is energized and ready for use, and shall continue thereafter until terminated by either party upon providing the other party with thirty (30) days prior written notice of termination.

9. Limitation on Damages
The Company will furnish electricity to operate the Equipment for dusk to dawn service or less, depending on the controlling device, each calendar year. The Company will use reasonable diligence at all times to provide continuous operation during the term. The Company shall not be liable to the Customer for any damages arising from complete or partial failure or interruption of service, shut down for repairs or adjustments, delay in providing or restoring service, or for failure to warn of any interruption of service or lighting.

10. Indemnification
Except for those claims, losses and damages arising out of Company's sole negligence, the Customer agrees to defend, at its own expense, and indemnify the Company for any and all claims, losses and damages, including attorney's fees and costs, which arise or are alleged to have arisen out of furnishing, design, installation, operation, maintenance or removal of the Equipment. The phrase "property damage" includes, but is not limited to, damage to the property of the Customer, the Company, or any third parties. For purposes of this indemnification, the "Company" shall be defined as Tampa Electric Company, its parent, Emera Inc., and all subsidiaries and affiliates thereof, and each of their respective officers, directors, affiliates, insurers, representatives, agents, servants, employees, contractors, and any successor corporations.

11. Outage Notification
The Customer shall be responsible for monitoring the function of the Equipment and for notifying the Company of all Equipment outages.

12. Tree Trimming
Failure of the Customer to maintain adequate clearance (e.g. trees and vegetation) around the Equipment may cause illumination obstruction and/or a delay in requested repairs or required maintenance.

Continued to Sheet No. 7.235

TECO TAMPA ELECTRIC AN EMERA COMPANY

FIRST REVISED SHEET NO. 7.260
CANCELS ORIGINAL SHEET NO. 7.260

Continued from Sheet No. 7.255

6. Customer Contribution in Aid of Construction

The Company shall pay for all normal Equipment installation costs, with the exception of the following: $_____ for _____. Refer to Section 5.2.6.1 of the Tampa Electric Tariff.

7. Monthly Payment

During the term of this Agreement, the Customer shall pay the Company monthly for the lighting services provided pursuant to Rate Schedule _____ as the rate schedule, which is on file with the Florida Public Service Commission, may be amended from time to time. All bills shall be due when rendered.

The current monthly base charges for facilities installed under this agreement are _____. Fuel and other adjustment clause charges and (where applicable) franchise fees and taxes per month under current tax rates pursuant to the Rate Schedule shall be _____. The total monthly charge shall be _____ per month.

The monthly charges specified in this agreement are tied to the tariff charges currently on file with the Florida Public Service Commission and may change during the term of this Agreement in accordance with filed changes to the relevant tariffs.

8. Term

This Agreement shall be effective on the later of the dates indicated on the signature block ("Effective Date") and shall continue on a month-to-month term (the "Term" as provided in the applicable Rate Schedule _____) beginning on the date one or more of the Equipment is installed and, if applicable, at least one light is energized and ready for use and shall continue thereafter until terminated by either party upon providing the other party with thirty (30) days prior written notice of termination.

9. Limitation on Damages

The Company will furnish electricity to operate the Equipment for dusk to dawn service or less, depending on the controlling device, each calendar year. The Company will use reasonable diligence at all times to provide continuous operation during the term. The Company shall not be liable to the Customer for any damages arising from complete or partial failure or interruption of service, shut down for repairs or adjustments, delay in providing or restoring service, or for failure to warn of any interruption of service or lighting.

10. Indemnification

Except for those claims, losses and damages arising out of Company's sole negligence, the Customer agrees to defend, at its own expense, and indemnify the Company for any and all claims, losses and damages, including attorney's fees and costs, which arise or are alleged to have arisen out of furnishing, design, installation, operation, maintenance or removal of the Equipment. The phrase "property damage" includes, but is not limited

 Customer Initials:_____ Date: _________

Continued to Sheet No. 7.265

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FIFTH REVISED SHEET NO. 7.765
CANCELS FOURTH REVISED SHEET NO. 7.765

APPENDIX A

Long-Term Facilities

Monthly Rental and Termination Factors

The Monthly Rental factor to be applied to the in-place value of the facilities as identified in the Long-Term Agreement is 0.91% per month plus applicable taxes.

If the Long-Term Rental Agreement for Facilities is terminated, a Termination Fee shall be computed by applying the following Termination Factors to the in-place value of the facilities based on the year in which the Agreement is terminated:

Year Agreement is Terminated	Termination Factors %
1	1.64
2	3.95
3	6.05
4	7.93
5	9.60
6	11.05
7	12.28
8	13.27
9	14.02
10	14.50
11	14.70
12	14.60
13	14.18
14	13.41
15	12.28
16	10.74
17	8.77
18	6.35
19	3.44
20	0.00

ISSUED BY: A. D. Collins, President **DATE EFFECTIVE:**

TECO
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FOURTEENTH REVISED SHEET NO. 8.070
CANCELS THIRTEENTH REVISED SHEET NO. 8.070

Continued from Sheet No. 8.061

CHARGES/CREDITS TO QUALIFYING FACILITY

A. Basic Service Charges

A Basic Service Charge will be rendered for maintaining an account for a Qualifying Facility engaged in either an As-Available Energy or Firm Capacity and Energy transaction and for other applicable administrative costs. Actual charges will depend on how the QF is interconnected to the Company.

QFs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

Daily Basic Service charges, applicable to QFs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	0.43	GST	0.63
GS	0.63	GSDT (secondary)	1.06
GSD (secondary)	1.06	GSDT (primary)	11.54
GSD (primary)	11.54	GSDT (subtrans.)	35.23
GSD (subtrans.)	35.23	SBDT (secondary)	1.06
SBD (secondary)	1.06	SBDT (primary)	11.54
SBD (primary)	11.54	SBDT (subtrans.)	35.23
SBD (subtrans.)	35.23	GSLDTPR	20.89
GSLDPR	20.89	GSLDTSU	126.72
GSLDSU	126.72	SBLDTPR	21.71
SBLDPR	21.71	SBLDTSU	127.55
SBLDSU	127.55		

When appropriate, the Basic Service Charge will be deducted from the Qualifying Facility's monthly payment. A statement of the charges or payments due the Qualifying Facility will be rendered monthly. Payment normally will be made by the twentieth business day following the end of the billing period.

Continued to Sheet No. 8.071

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SEVENTH REVISED SHEET NO. 8.312
CANCELS SIXTH REVISED SHEET NO. 8.312

Continued from Sheet No. 8.308

Should the CEP elect a Net Billing Arrangement, the hourly net capacity and energy sales delivered to the purchasing utility shall be purchased at the utility's avoided capacity and energy rates, where applicable, in accordance with FPSC Rules 25-17.0825 and 25-17.0832, F.A.C. Purchases from the interconnecting utility shall be billed at the retail rate schedule, under which the CEP load would receive service as a customer of the utility.

Although a billing option may be changed in accordance with FPSC Rule 25-17.082, F.A.C., the Contracted Capacity may only change through mutual negotiations satisfactory to the CEP and the Company.

Basic Service charges that are directly attributable to the purchase of firm capacity and energy from the CEP are deducted from the CEP's total monthly payment. A statement covering the charges and payments due the CEP is rendered monthly and payment normally is made by the 20th business day following the end of the Monthly Period.

CHARGES/CREDITS TO THE CEP:

1. **Basic Service Charges:** A Basic Service Charge will be rendered for maintaining an account for the CEP engaged in either an As-Available Energy or firm capacity and energy transaction and for other applicable administrative costs. Actual charges will depend on how the CEP is interconnected to the Company.

   CEPs not directly interconnected to the Company, will be billed $990 monthly as a Basic Service Charge.

   Daily Basic Service charges, applicable to CEPs directly interconnected to the Company, by Rate Schedule are:

Rate Schedule	Basic Service Charge ($)	Rate Schedule	Basic Service Charge ($)
RS	0.43	GST	0.63
GS	0.63	GSDT (secondary)	1.06
GSD (secondary)	1.06	GSDT (primary)	11.54
GSD (primary)	11.54	GSDT (subtrans.)	35.23
GSD (subtrans.)	35.23	SBDT (secondary)	1.06
SBD (secondary)	1.06	SBDT (primary)	11.54
SBD (primary)	11.54	SBDT (subtrans.)	35.23
SBD (subtrans.)	35.23	GSLDTPR	20.89
GSLDPR	20.89	GSLDTSU	126.72
GSLDSU	126.72	SBLDTPR	21.71
SBLDPR	21.71	SBLDTSU	127.55
SBLDSU	127.55		

Continued to Sheet No. 8.314

ISSUED BY: A. D Collins, President **DATE EFFECTIVE:**

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FIRST REVISED SHEET NO. 8.318
CANCELS ORIGINAL SHEET NO. 8.318

A determination of whether or not such service is likely to result in higher cost electric service will be made by the Company by evaluating the results of an appropriately adjusted FPSC approved cost effectiveness methodology, in addition to other modeling analyses.

3. In accordance with FPSC Rule 25-17.089, F.A.C., upon request by a CEP, the Company shall provide transmission service in accordance with its OATT to wheel As-Available Energy or firm capacity and energy produced by the CEP from the CEP to another electric utility.

4. The rates, terms, and conditions for any transmission and ancillary services provide to the CEP shall be those approved by the FERC and contained in the Company's OATT.

5. A CEP may apply for transmission and ancillary services from the Company in accordance with the Company's OATT. Requests for service must be submitted on the Company's Open Access Same-Time Information System ("OASIS"). The Company's contact person, phone number and address is posted and updated on the OASIS and can be viewed by the public on the Internet at the address: http://www.oasis.oati.com/TEC/index.html

6. If the CEP is located outside of the Company's transmission area, then the CEP must arrange for long term firm 3rd-party transmission, ancillary services and an Interconnection Agreement on all necessary external transmission paths for the term of the contract.

PROCEDURE FOR PROCESSING STANDARD OFFER CONTRACTS: Within 60 days of the receipt of a signed, completed Standard Offer Contract, the Company shall either accept and sign the Standard Offer Contract and return it within 5 days to the CEP or petition the Commission not to accept the Standard Offer Contract and provide justification for the refusal.

All Standard Offer Contracts received will be given equal consideration and each will be reviewed in accordance with the Company's Evaluation Procedure for Standard Offer Contracts. The criteria and procedure used to evaluate Standard Offer Contracts are attached to the Standard Offer Contract as Appendix I.