

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida
Public Utilities Company.

DOCKET NO. 20240099-EI

ORDER NO. PSC-2025-0114-PAA-EI

ISSUED: April 7, 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

NOTICE OF PROPOSED AGENCY ACTION
ORDER APPROVING IN PART AND DENYING IN PART PETITION FOR RATE
INCREASE BY FLORIDA PUBLIC UTILITIES COMPANY

BY THE COMMISSION:

NOTICE is hereby given by the Florida Public Service Commission that the action discussed herein, except for not requiring a refund of interim rates and requiring proof of adjustment of books and records, is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code (F.A.C.).

Background

Florida Public Utilities Company (FPUC or Company) filed a test year notification letter with the Florida Public Service Commission (Commission) on June 18, 2024, in which the Company indicated its intent to seek a permanent increase in its rates and charges based on a test year ending December 31, 2025, and a request for an interim rate increase. On August 22, 2024, FPUC filed its petition for an increase in base rates, as well as minimum filing requirements schedules (MFRs) and direct testimony of 10 witnesses. The Company is engaged in business as a public utility providing electric service as defined in Section 366.02, Florida Statutes (F.S.), and is subject to our jurisdiction. FPUC serves approximately 15,000 retail customers in Calhoun, Liberty, and Jackson counties in the Company's Northwest Division and approximately 18,100 retail customers in Nassau County in its Northeast Division.

FPUC has requested an increase in base rates to generate an additional \$12,593,450 in annual revenues, using our proposed agency action (PAA) process under Section 366.06(4), F.S. The requested increase, according to FPUC, will provide the Company with an opportunity to earn an overall rate of return of 6.89 percent on the Company's plant and property used to serve its customers. This overall rate of return is based on a cost of equity of 11.30 percent. The Company based its request on a 13-month average rate base of \$150,053,096 for the projected test year ending December 2025.

In its petition, FPUC stated that the key drivers for the proposed rate increase are: (1) investments tied to improvements in reliability: purchases and renovation of substations,

increased costs associated with safety regulations, and increased depreciation expenses, (2) supply chain shortage and increased prices for labor, fuel, materials, insurance, high inflation, additional costs for cyber-security improvements, and (3) implementation of a new Customer Information System (CIS).

FPUC stated in its petition that the requested test year period ending December 31, 2025, is the most relevant period upon which the Company's operations should be analyzed for purposes of establishing rates for the period in which the new rates will be in effect. The Company further stated that this period will be indicative of its actual revenues, expenses, and investment during the first 12 months that the new rates will be in effect. We last granted FPUC an approximately \$3.75 million rate increase by Order No. PSC-14-0517-S-EI.¹

On September 4, 2024, the Office of Public Counsel (OPC) filed its notice of intervention in this docket and the order acknowledging the intervention was issued on September 5, 2024.² On September 4, 2024, FPUC filed revisions to MFR Schedules B-2 and G-3 to correct a reference to the prior rate case order. No numeric values were changed.

FPUC has also requested an interim rate increase in its base rates and charges to generate \$1,812,869 in additional gross revenues until the permanent rates become effective. The Company has based its interim request on a historical test year which ended December 31, 2023. In its petition, FPUC stated that it will hold any revenues collected, subject to refund, with interest at a rate determined pursuant to Rule 25-6.0435(3), Florida Administrative Code (F.A.C.) and that it be allowed to collect the interim increase subject to a corporate undertaking. By Order No. PSC-2024-0441-PCO-EI, we suspended the proposed permanent rates and approved the requested interim rate increase.³

During the review process Commission staff conducted an audit of FPUC based on the historical test year ended December 31, 2023. The auditors report and findings were issued on December 20, 2024.⁴ Additionally, during the review process, noticed in-person customer service hearings were held on December 4, 2024, in Fernandina Beach and on January 8, 2025, in Marianna. Twelve customers provided testimony at the December 4, 2024 service hearing and 20 customers provided testimony at the January 8, 2025 service hearing. Additionally, ten customers and the Jackson County Board of County Commissioners opposing the proposed rate increase have filed written comments in the correspondence side of the docket as of February 10, 2025.

This order addresses FPUC's requested permanent rate increase. We have jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.06 and 366.071, F.S.

¹ Order No. PSC-14-0517-S-EI, issued September 29, 2014, in Docket No. 20140025-EI, *In re: Application for rate increase by Florida Public Utilities Company*.

² Order No. PSC-2024-0408-PCO-EI, issued September 5, 2024, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

³ Order No. PSC-2024-0441-PCO-EI, issued October 14, 2024, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

⁴ Document No. 10324-2024.

Decision

I. Test Year

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. FPUC proposed the year ending December 31, 2025 as its test year for this docket, stating that it will “reflect actual conditions, be indicative of the actual revenues, expenses, and investment during the first 12-months that new rates will be in effect.”⁵

We agree with FPUC that the 12 months ending December 31, 2025, provides a reasonable basis for assessing FPUC’s financial and operational performance, allowing for a thorough evaluation of revenues, expenses, and rate base investment. Further, we find that this test period ensures that the projections reflect current trends and future conditions, making it a sound period for regulatory and financial planning. Therefore, we find that the projected test period of the twelve months ending December 31, 2025, is appropriate.

II. Forecasts

This section addresses whether FPUC’s forecasts of customers, energy (kWh), and demand (kW) by revenue and rate class for the projected test year are appropriate. The methodologies, assumptions, and data inputs utilized by the Company to project customer counts, energy consumption, and peak demand across its various rate classes were analyzed.

FPUC currently provides electric service to customers across two separate service areas. FPUC provided the forecasts for these two service areas separately due to geographical differences between the two areas. The Northeast division, headquartered in Fernandina Beach, Florida, serves customers on Amelia Island while the Northwest division, based in Marianna, Florida, serves customers in the surrounding counties of Jackson, Calhoun, and Liberty.

A. Customers

FPUC explained that the customer count forecasts for each rate class were developed using a time trend based on 2020 to 2023 data, and then adjusted for known growth factors and growth estimates for service territories and rate classes.⁶ Each service territory is composed of six rate classes – Residential (RS), General Service (GS or Commercial Small), General Service Demand (GSD or Commercial), General Service Large Demand (GSLD or Large Commercial), General Service Large Demand 1 (GSLD 1 or Industrial), and Lighting (Outdoor Lighting and Street Lighting).

The Company served an average monthly total of 33,091 customers across the two divisions in 2023, and projected its total customer count to increase to 33,190 in 2024 (0.2 percent growth), and then increase again to its test year projection of 33,290 customers in 2025 (0.3 percent growth). The Company’s historical and forecasted customer data, by rate class and division, is broken down further in the tables below.

⁵ Docket No. 20240099-EI: *Petition for approval of rate increase and request for interim rate relief*, Document No. 08581-2024.

⁶ Response No. 2 in Staff’s Fourth Data Request, Document No. 09634-2024.

Table 1
FPUC Average Monthly Customers – Northeast Division

Year	Residential	Commercial Small	Commercial	Large Commercial	Industrial	Lighting	Total	Percent Growth (Y/O/Y)
2021	15,343	1,700	253	11	2	486	17,795	-
2022	15,440	1,710	250	11	2	475	17,888	0.52%
2023	15,599	1,723	253	11	2	472	18,060	0.96%
2024*	15,645	1,727	255	11	2	469	18,109	0.27%
2025**	15,690	1,728	255	10	2	470	18,155	0.25%

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff's Fourth Data Request and Response No. 2 in Staff's Twenty-Eighth Data Request.

Table 2
FPUC Average Monthly Customers – Northwest Division

Year	Residential	Commercial Small	Commercial	Large Commercial	Industrial	Lighting	Total	Percent Growth (Y/O/Y)
2021	10,004	2,020	395	13	0	2,448	14,880	-
2022	10,076	2,056	400	13	0	2,421	14,966	0.58%
2023	10,120	2,058	408	14	0	2,431	15,031	0.43%
2024*	10,162	2,063	410	14	0	2,432	15,081	0.33%
2025**	10,205	2,070	413	15	0	2,432	15,135	0.36%

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff's Fourth Data Request and Response No. 2 in Staff's Twenty-Eighth Data Request.

Table 3
FPUC Average Monthly Customers – Total Combined

Year	Residential	Commercial Small	Commercial	Large Commercial	Industrial	Lighting	Total	Percent Growth (Y/O/Y)
2021	25,347	3,720	648	24	2	2,934	32,675	-
2022	25,516	3,766	650	24	2	2,896	32,854	0.55%
2023	25,719	3,781	661	25	2	2,903	33,091	0.72%
2024*	25,807	3,790	665	25	2	2,901	33,190	0.30%

2025**	25,895	3,798	668	25	2	2,902	33,290	0.30%
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*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff's Fourth Data Request and Response No. 2 in Staff's Twenty-Eighth Data Request.

The Company's historical customer data was analyzed for both divisions. The historical data for the Company's Northeast division shows moderate growth (approximately 1.3 percent per year since 2015). However, the Company forecasted 0.3 percent growth for both 2024 and 2025. The Company explained that the lower projected growth compared to the historical average is due to the service area on Amelia Island being nearly fully-developed, with less opportunities each year for new developments, which the Company supported with a list of residential building permits issued by year, showing a substantial reduction since 2019.⁷ The historical customer data for Company's Northwest division data shows minimal growth in recent years and virtually zero growth since 2015.⁸ FPUC explained that the Northwest division is more rural and still recovering from the effects of Hurricane Michael. Both of these factors support FPUC's forecasts of minimal growth in the test year.

Based on our review of the Company's customer forecast methodology, past historical trends, and the Company's response to our data requests, we find that FPUC's customer count forecast of 33,290 for the 2025 test year is reasonable.

B. Energy Sales

FPUC's projects total energy sales of 613,810,520 kWh for the 2025 test year, as detailed in its MFRs.⁹ FPUC witness Taylor provided forecast models for the Company's RS class, the GS class, and the GSD class, by service area, and referred to these classes as Residential, Commercial Small, and Commercial, respectively. These models detail each service area's historical and forecasted use-per-customer (UPC) by rate class which, when multiplied by the service area's projected customer counts, result in the service area's projected energy sales (in kWh) for the test year for those rate classes.¹⁰ Company total projected sales are simply the sum of FPUC's two service area's projected sales.

The Company's models used to project UPC for these rate classes utilized a 10-year average of Cooling Degree Days (CDDs) and Heating Degree Days (HDDs) and a time trend.¹¹ We analyzed FPUC's inputs and assumptions used in its forecast models for these rate classes. It is unusual for a company's usage models to only consist of weather variables and a time trend variable, neglecting to include other variables that are often found to impact sales, such as energy price, average income, efficiency standards, etc. Even so, we agree with witness Taylor that the UPC models are statistically significant and the regression models' independent variables explain a

⁷ Response No. 2 in Staff's Twenty First Data Request, Document No. 00015-2025.

⁸ Response No. 6 in Staff's Fourth Data Request, Document No. 09634-2024.

⁹ MFR Schedule E-6a.

¹⁰ Witness Taylor Direct Testimony, Page 7, lines 2-5, Document No. 08591-2024.

¹¹ MFR Schedule F-5, page 1 of 3.

relatively high percentage of the variation in UPC for these rate classes.¹² The Company’s historical and forecasted UPC data for the Residential, Commercial Small, and Commercial rate classes are detailed in the tables below.

Table 4
FPUC Average Annual UPC (kWh) – Residential

Year	Northeast Division	Percent Growth (Y/O/Y)	Northwest Division	Percent Growth (Y/O/Y)
2019	12,284	-	12,753	-
2020	12,090	-1.58%	12,317	-3.43%
2021	11,920	-1.40%	12,129	-1.52%
2022	11,886	-0.29%	12,115	-0.11%
2023	11,528	-3.01%	11,887	-1.89%
2024*	11,579	0.44%	12,052	1.39%
2025**	11,439	-1.21%	11,901	-1.25%

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff’s Fourth Data Request and Response No. 2 in Staff’s Twenty-Eighth Data Request.

Table 5
FPUC Average Annual UPC (kWh) – Commercial Small

Year	Northeast Division	Percent Growth (Y/O/Y)	Northwest Division	Percent Growth (Y/O/Y)
2019	17,302	-	14,239	-
2020	16,127	-6.80%	13,440	-5.61%
2021	16,746	3.84%	13,594	1.15%
2022	16,506	-1.43%	14,532	6.89%
2023	16,608	0.61%	14,504	-0.19%
2024*	16,608	0.00%	14,729	1.55%
2025**	16,631	0.14%	15,026	2.02%

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff’s Fourth Data Request and Response No. 2 in Staff’s Twenty-Eighth Data Request.

¹² Response No. 8 in Staff’s Twenty first Data Request, Document No. 00015-2025.

Table 6
FPUC Average Annual UPC (kWh) – Commercial

Year	Northeast Division	Percent Growth (Y/O/Y)	Northwest Division	Percent Growth (Y/O/Y)
2019	306,699	-	205,482	-
2020	294,331	-4.03%	198,170	-3.56%
2021	303,547	3.13%	201,343	1.60%
2022	324,685	6.96%	205,583	2.11%
2023	315,008	-2.98%	200,648	-2.40%
2024*	301,352	-4.34%	199,780	-0.43%
2025**	307,390	2.00%	203,084	1.65%

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Supplemental Response No. 12 in Staff's Fourth Data Request and Response No. 2 in Staff's Twenty-Eighth Data Request.

For the Company's large commercial and industrial rate classes, General Service Large Demand (GSLD) and General Service Large Demand1 (GSLD1), due to the small number of customers (27 total customers across both divisions in 2023) and the minimal customer growth expected, the usage projections were forecasted separately utilizing a combination of past usage along with identified known changes in each individual customer's operations.¹³

For the Company's lighting customers, consisting of Outdoor Lighting (OL) and Street Lighting (SL), the customer growth rate from their respective service territories was used as a proxy for the expected growth of lighting energy sales.¹⁴ FPUC explained this decision was due to the Company's expectation that the recent growth in lighting revenues will not continue, partly due to the SL class now being closed to new enrollment. The Company's historical usage as well as the Company's explanation for any deviations from the historical norm was analyzed and we find that the test year usage projections for these rate classes are reasonable.

Based on our review of the Company's MFR's, models, assumptions, results, as well its responses to data requests, we find that FPUC's total energy sales projection of 613,810,520 kWh for the 2025 test year, is reasonable.

C. Demand

FPUC currently has three rate classes that employ a demand component – the GSD class, the GSLD class, and the GSLD1 class. FPUC stated that the forecasts of billing demand for the GSD and GSLD rate classes by service area were based on the historical relationship with CDDs, HDDs, and a time trend variable, combined with the forecast of the number of customers by rate

¹³ Response No. 9 in Staff's Fourth Data Request, Document No. 09634-2024.

¹⁴ MFR Schedule F-5, page 1 of 3.

class. In some cases, the demand forecasts were adjusted based on known and measurable changes to customer’s operations. For example, for one of the Northeast Division’s Large Commercial Customers, a building owned by the customer was demolished, therefore FPUC made an adjustment to the forecasted demand for that customer class.¹⁵

The Company explained that since the GSLD1 rate class consists of only two customers (both in the Northeast Division), the test year demand was forecasted “directly” for these two customers.¹⁶ The Company is proposing the GSLD1 customer and lone GSLD1 Standby Customer be consolidated, eliminating the Standby tariff. The Company’s historical and forecasted demand, by rate class and division, are detailed in the tables below.

Table 7
FPUC Demand Forecasts (kW) – Northeast Division

Year	Commercial (GSD)	Large Commercial (GSLD)	Industrial (GSLD1)	Industrial (GSLD Standby)
2020	218,333	75,271	212,600	312,000
2021	222,241	78,427	121,900	312,000
2022	239,374	76,160	171,600	312,000
2023	228,906	77,603	232,100	312,000
2024*	230,100	79,933	199,500	312,000
2025**	232,090	72,099	192,567	312,000

*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Response No. 3 in Staff’s Twenty-eighth Data Request.

Table 8
FPUC Demand Forecasts (kW) – Northwest Division

Year	Commercial (GSD)	Large Commercial (GSLD)
2020	304,271	89,104
2021	328,378	89,334
2022	333,022	93,374
2023	331,590	94,323
2024	323,984	94,702

¹⁵ Response No. 4 in Staff’s Fourth Data Request, Document No. 09634-2025.

¹⁶ MFR Schedule F-5, page 1 of 3

2025	333,565	93,055
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*4 months of actual data, 8 months of forecasted data.

**Forecasted Test Year.

Source: Response No. 3 in Staff's Twenty-eighth Data Request.

We have reviewed the Company's historical demand data, its forecast of demand for the 2025 test year, as well as the Company's explanation for any measurable deviations, and find that the Company's demand projections for the test year are reasonable.

D. Estimated Revenues

In general, to calculate total revenues from sales of electricity, first, the Company's forecasted customer counts for each class are multiplied by the present customer charge for that class to arrive at its base customer charge revenue. Similarly, the forecasted usage (in kWh) for each customer class are multiplied by their respective present energy charge to arrive at its energy charge revenue. Lastly, for the rate classes with a demand component, forecasted demand (in kW) for each applicable class is multiplied by the present demand charge to calculate demand revenue. These three components are then summed to yield total revenues from sales of electricity.

FPUC provided forecasted customer counts, energy sales, and demand (where applicable) for all of the Company's rate classes for the 2025 test year and, we have made no adjustments to such forecasts. We have confirmed that FPUC used the correct current rates and forecasted units for all customer classes in its calculations of test year revenue, arriving at a total revenue from sales of electricity by rate class at present rates of \$24,375,589, as summarized in Table 9 below.

Table 9
Estimated Revenues from Sales of Electricity by Rate Class at Present Rates - 2025 Test Year

Customer Class	Customer Charge Revenue	Energy Charge Revenue	Demand Charge Revenue	Total Revenue
Residential Service (RS)	\$5,267,161	\$8,396,460	\$0	\$13,663,622
General Service (GS)	\$1,269,069	\$1,736,912	\$0	\$3,005,981
General Service Demand (GSD)	\$660,118	\$887,789	\$2,542,617	\$4,090,524
General Service Large Demand (GSLD)	\$46,596	\$198,578	\$1,060,285	\$1,305,459
General Service Large Demand 1 (GSLD 1)	\$23,395	\$0	\$597,419	\$620,814

Lighting Service (OL and SL)	\$1,689,189	\$0	\$0	\$1,689,189
Totals	\$8,955,529	\$11,219,739	\$4,200,321	\$24,375,589

Source: MFR Schedule E-13c.

Based on our analysis, we find that FPUC’s estimated revenues from sales of electricity by rate class at present rates for the projected test year are appropriate. No adjustments are necessary.

E. Non-payroll trend factors

Trend factors are numeric escalators (or multipliers) that are applied to historic expenses as an operations and maintenance (O&M) benchmarking tool and for preparing the forward-looking test year O&M expense budget amounts. O&M expenses that have trend factors applied are generally grouped as “payroll” and “non-payroll” expenses. According to FPUC’s witness Napier, the most commonly used trend factors for non-payroll expenses are inflation and inflation times customer growth.¹⁷

Witness Napier stated that FPUC used inflation, customer growth, payroll growth, a revenue trend factor, and two factors in combination for projecting test year O&M expenses.¹⁸ Witness Napier asserts the O&M expenses from the 2023 historic year were used as the starting point for developing the 2024 and 2025 test year estimates. From that starting point, the Company made all necessary adjustments through the application of trend factors, as reflected in the MFR Schedules associated with this rate proceeding. Witness Napier further stated that all appropriate trend factors were used in this manner, and when trend factors were not used, direct expense projections were used, which relied upon the expertise of internal managers or known items impacting certain expenses as a basis for the projection.¹⁹ Witness Napier further stated that the Company’s application of trend factors in the instant case is consistent with how trend factors were used in prior rate proceedings.²⁰

FPUC used a weighted average of Consumer Price Index for All Urban Consumers (CPI-U) as its measure of inflation.²¹ The Company used an inflation trend factor to project certain non-payroll O&M expenses for the 2025 projected test year.²² The Company states that its forecasted data was provided by the Bloomberg Weighted Average CPI Forecast, which estimated average inflation values of 2.84 percent for 2024, and 2.31 percent for 2025.²³ FPUC stated that the Bloomberg forecasts are derived from monthly and quarterly surveys it conducted

¹⁷ Direct testimony of Michelle Napier, page 20, Document No. 08583-2024.

¹⁸ Direct testimony of Michelle Napier, page 20, Document No. 08583-2024.

¹⁹ Direct testimony of Michelle Napier, page 18, Document No. 08583-2024.

²⁰ Direct testimony of Michelle Napier, page 19, Document No. 08583-2024.

²¹ Response No. 1 in Staff’s 13th Data Request, Document No. 09977-2024.

²² Direct testimony of Michelle Napier, page 20, Document No. 08583-2024.

²³ Response No. 1 in Staff’s 13th Data Request, Document No. 09977-2024.

and from forecasts submitted by various banks. FPUC also stated the weighted average incorporates more than 40 different economists' expectations to calculate its weighted average CPI. FPUC believes the derived averages from Bloomberg are appropriate for use in this proceeding, since the weighted average incorporates multiple perspectives.²⁴ FPUC stated it did not consider any alternative sources of CPI other than Bloomberg's.

The Company alleges that the average CPI is the most appropriate inflation trend factor, as it was approved in the last FPUC electric rate case, as well as the Company's 2022 Florida natural gas rate case.²⁵ Therefore, its use in this proceeding demonstrates and promotes consistent use and application across all the Company's Florida regulated operations.²⁶

FPUC's 2023 inflation forecast for 2024 (2.84 percent) used to prepare its budget in this case is conservative relative to the similar forecast prepared at a later point in time (an inflation forecast of 2024 prepared in September of 2024, showing 2.90 percent). A similar analysis reflects that FPUC's 2023 inflation forecast for 2025 (2.31 percent) remained the same for 2025, as shown in Table 10 below. We find that FPUC's trend factors for inflation used to prepare its test year budgets are reasonable.

Table 10
Projections of CPI in Bloomberg Forecasts

Bloomberg's Weighted Average CPI	Date of Forecast	
	December 2023	September 2024
Forecast of CPI for 2024	2.84 percent	2.90 percent
Forecast of CPI for 2025	2.31 percent	2.31 percent

Source: Document No. 09904-2024, FPUC's response to staff's 11th data request, No. 2 and Document No. 09977-2024, FPUC's response to staff's 13th data request, No. 4.a.

A customer growth trend factor is a composite of elements that influence the rate at which a customer base expands over time. FPUC estimates customer growth at 0.30 percent for 2024, and 0.31 percent for 2025.²⁷ FPUC utilized the Bureau of Labor Statistics data as a resource for its customer growth data.²⁸ FPUC's customer growth trend factor is a fallout calculation of the customer count forecasts by rate class addressed above.

FPUC based the customer growth trend factor on a detailed analysis, in which FPUC tested the reasonableness of its results from "revenue related projections used within this rate

²⁴ Response No. 1 in Staff's 13th Data Request, Document No. 09977-2024.

²⁵ 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 - Fort Meade, and Florida Public Utilities Company - Indiantown Division.*

²⁶ Response No. 4.a in Staff's 13th Data Request, Document No. 09977-2024.

²⁷ MFR Schedule C-33, Page 177, line 15, Document No. 08594-2024.

²⁸ Attachment 11.1, response to Staff's 11th Data Request, Document No. 09904-2024.

proceeding.”²⁹ The application of customer growth and other trend factors used in this proceeding is consistent with how expense projections were developed in prior FPUC rate proceedings. Based on these facts, we find that FPUC’s 2024 and 2025 projections of customer growth (0.30 percent for 2024 and 0.31 percent for 2025) used for forecasting its test year budgets are reasonable.

In addition to the inflation and customer growth trend factors, MFR Schedule C-7 reflects that FPUC used a revenue trend factor for the limited purpose of projecting uncollectible expenses for the forecasted test year budget. In addition, MFR Schedule C-7 reflects that FPUC used two combination trend factors, or factors that were the product of multiplying stand-alone trend factors. The combination trend factors are inflation and customer growth.

Based on the above, we find that the non-payroll trend factors appropriate for forecasting FPUC’s 2024 and 2025 test year budgets include: for 2024, 2.84 percent for inflation, 0.30 percent for customer growth, and 0.34 percent for revenue; for 2025, 2.31 percent for inflation, 0.31 percent for customer growth, and (0.09) percent for revenue. We further find that the combination of customer and inflation trend factors for 2024 and 2025 are also appropriately used for this purpose.

III. Quality of Service

Pursuant to Section 366.041(1), 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. In making this assessment, we reviewed:

1. Complaints filed with the Commission via its Consumer Activity Tracking System (CATS) from January 1, 2020, through October 24, 2024.³⁰
2. Complaints filed with FPUC from January 1, 2020, through October 24, 2024.
3. Testimony made by customers at the in-person service hearings held on December 4, 2024 (Northeast division) and January 8, 2025 (Northwest division).
4. Correspondence filed in the docket file.

There were 94 complaints logged in the CATS system and 127 complaints were received by FPUC over the five-year period.³¹ FPUC serves approximately 33,100 customers. Table 11 shows these complaints by source and type. The majority of these complaints are related to billing issues which include concerns regarding high bills, overall rates and charges, and bill discrepancies.

²⁹ Direct testimony of Michelle Napier, page 20, Document No. 08583-2024.

³⁰ There were 138 customer contacts transferred directly to FPUC via the Commission’s Transfer-Connect (Warm-Transfer) System. This system allows the Commission to directly transfer a customer to FPUC’s customer service personnel for resolution.

³¹ Response No. 1 in Staff’s Tenth Data Request, Document No. 09893-2024.

Table 11
Customer Complaints

Year	FPUC Complaints		CATS Complaints	
	Quality of Service	Billing Issues	Quality of Service	Billing Issues
2020	7	4	1	4
2021	7	21	2	19
2022	8	20	0	19
2023	8	22	2	23
2024(January – October)	6	24	1	23
Total	36	91	6	88

Source: Response No. 1 in Staff's Tenth Data Request, Document No. 09893-2024.

Of the 94 CATS complaints, there were 23 complaints (22 billing complaints and one quality of service) that appeared to demonstrate Commission rule violations associated with improper disconnects, improper bills and/or not providing timely responses. Based on the above, the total complaints from CATs and FPUC (94+127) averages to approximately 44 complaints per year. When compared to the Company's total customer base of 33,100 customers, the resulting calculation is approximately 0.1 percent.

A total of 33 customers spoke at both service hearings. The principle comment made by customers was opposition to the proposed rate increase. Customers also discussed: (1) difficulties reaching FPUC by phone; (2) a lack of physical locations to pay bills; and (3) inaccurate bills. There were also 6 customers that spoke in favor of FPUC's service quality.

Through data requests, FPUC indicated that it was aware, prior to the service hearings, of the issues expressed by customers regarding difficulty contacting them. Since mid-2023, FPUC has made efforts to improve its call handling practices by increased staffing and enhanced training. FPUC's call center currently consists of approximately 30 customer service agents and the average wait-time is 4 minutes and 36 seconds. In addition to calling the Company, customers may also contact them by mail, email, or its website.³² As stated above, customers also expressed concern regarding a lack of physical locations available to pay their bills. FPUC indicated that customers may find retail centers, where bills can be paid in-person with no additional fees, on the back of their bill or on the Company's EZ-Pay webpage using their account number.³³

Customers may also pay their bills by mail or EZ-Billing, when automatic payments are set up to a checking or savings account, with no fees. There is a payment fee of \$2.25 per \$750 for bills paid by phone or EZ-Pay one-time payments. In an effort to resolve the issues brought forth

³² Response No. 1 in Staff's Twenty Ninth Data Request, Document No. 00414-2025.

³³ Response No. 2 in Staff's Twenty Seventh Data Request, Document No. 00339-2025.

at the service hearings, the Company reached out to all of the customers that provided testimony.³⁴ In addition, by letter dated February 10, 2025, the Company notified the Commission of the following additional customer outreach actions: FPUC (1) added a website page to further explain bill components and the Company's rate increase request; (2) initiated informative social media posts regarding conservation programs and payment assistance; and (3) invited customers to its in-person event in the Northwest division to address further questions and to provide payment information and assistance.³⁵

Additionally, 11 comments have been filed in the docket file that address the rate increase and customer service difficulties. Of these 11 comments, one was a letter from the Jackson County Board of County Commissioners opposing the overall rate increase. In order to improve its quality of service, FPUC has recently implemented the following:

1. Five9 – provides updates to call flow options for inbound contacts to deliver their call to the appropriately skilled agent via a single dashboard.
2. Voice of the Customer – gathers direct customer feedback via post-call and email surveys, identifies trends and develops plans to deliver improvements in the areas customers find most beneficial.
3. Service Excellence Strategy – provides the blueprint for actualizing commitment to improved customer service by focusing on the quality of service across every touchpoint.
4. New Customer Information System (CIS) – provides customer communication improvements such as notification and preference management system that will allow customers to set channel and contact preferences for outbound communications for billing and payments, and marketing, which will allow the customer to control how and when the Corporation contacts them.

Upon review we find that FPUC's overall quality of service is adequate given the relatively low average number of complaints with respect to its total customer base. Furthermore, the recent improvements by FPUC (e.g., Five9, Voice of the Customer, and CIS) demonstrate the Company's efforts to enhance its customer service and overall quality of service.

IV. Rate Base

A. Substations and Transmission Assets

In its 2025 projected test year, FPUC has included the costs associated with the acquisition and replacement of four substations and a transmission line in its Northwest Florida territory, and replacement/rebuild of two FPUC-owned substations in its Northeast Florida territory.

³⁴ Response No. 3 in Staff's Twenty Ninth Data Request, Document No. 00414-2025 and Document No. 00652-2025, filed February 3, 2025, in Docket No. 20240099-EI.

³⁵ Document No. 00905-2025, filed February 10, 2025, in Docket No. 20240099-EI.

The Northwest Florida acquisitions will be purchased from Florida Power & Light Company (FPL), and the purchase is expected to be completed by February 2025. FPUC indicated that within the purchased assets, certain equipment, primarily substation transformers, will need to be replaced due to age, and additional modifications, such as the addition of redundant transformers, will be necessary to improve the reliability and resiliency of these assets.³⁶ FPUC also indicated that so far, only a visual inspection has been conducted to determine which equipment will potentially need to be replaced.³⁷ Based on this inspection, FPUC determined that several transformers are approximately 58 years old and therefore nearing the end of their useful life based on the average service life of distribution substation equipment in Florida, which ranges from 45 to 60 years. FPUC stated that the age of the other substation equipment could not be determined visually; however, a visual assessment of the equipment and substation design was completed to identify equipment that would likely require replacements/updates.

Once the substation and transmission assets have been acquired, FPUC intends to review previous testing results and conduct additional testing for these assets to confirm what equipment will require replacement or updates. The replacement/update of these assets is expected to be completed by December 2025. The purchase of these assets is expected to cost approximately \$4.2 million, and the replacement/update of these assets is expected to cost approximately \$6.5 million. FPUC expects the acquisition of these assets to result in annual savings to customers of approximately \$1.4 million by eliminating the distribution charge paid to FPL for the provision of purchased power to FPUC from these assets. These projected savings will be passed on to FPUC's customers through reduced purchased power costs and a reduced fuel factor.³⁸

For FPUC's two Northeast Florida substations, AIP and JL Terry, FPUC indicated that aging equipment needs to be replaced, and the substations need to be rebuilt for safety and regulatory compliance. In response to staff's data requests, FPUC indicated that the AIP substation metal clad switchgear, which was placed in-service in the 1970s, has reached its end of useful life based on testing and the resulting repairs over the last 15 years.³⁹ The load currently served by this substation cannot be served from another substation; therefore, FPUC intends to rebuild this substation using the existing transformers to reduce costs. Regarding the JL Terry substation, FPUC indicated that due to load growth and to match impedance of the other transformer at this substation, FPUC intends to replace the 30 megavolt-amperes (MVA) transformer with a new 40 MVA transformer. Upon replacement, the current 30 MVA transformer would be relocated to the step down substation to replace a 20 MVA transformer that has been in service for over 70 years and has reached its end of useful life. The rebuild of the AIP substation is expected to be completed by April 2025, and the replacement at the JL Terry substation is expected to be completed by November 2025. These projects are expected to cost approximately \$6.3 million and \$2.4 million, respectively.

³⁶ Response No. 1 in Staff's Sixth Data Request, Document No. 09794-2024.

³⁷ Response No. 4 in Staff's Twentieth Data Request, Document No. 00017-2025.

³⁸ Document No. 00396-2025.

³⁹ Response No. 1 in Staff's Sixth Data Request, Document No. 09794-2024.

To complete the above projects, FPUC has selected a contractor who has been previously vetted against other contractors by, and has an existing contract with, the Company. The project cost estimates for the replacement/rebuild projects were provided by the contractor, in consultation with FPUC personnel, and the cost estimate for the acquisitions was developed by FPL based on the current depreciated book value of the assets, and the costs associated with separation of the assets.

We have reviewed these projects and find that they are necessary to maintain and improve the reliability and integrity of FPUC's electric system. Additionally, the acquisition of the Northwest Florida substation and transmission assets is expected to save customers approximately \$1.4 million annually in avoided distribution charges. For these reasons, FPUC's proposed acquisition and replacement of substations and transmission assets are approved for inclusion in the 2025 projected test year.

FPUC has requested certain accounting treatment for the costs associated with the substations discussed in this issue. Specifically, the substation assets are entering into service throughout the projected test year concluding in December 2025.⁴⁰ Due to the staggered in-service of the various substation investments throughout 2025, the associated revenue requirements under the normal ratemaking process are less than they would otherwise be had the assets been in service for the full 13 months of the rate-setting test period. This is because in ratemaking, the average rate base value is determined on a 13-month basis, while any associated operating expenses generally begin at the point of in-service. Thus, assets must be in-service for the entire duration of the test period for the total associated revenue requirement to be included in service rates. However, FPUC has essentially requested that full-year revenue requirements associated with the substation investments be included in the new rates set in this proceeding. This would be achieved by using year-end account balances of the associated investments rather than 13-month average balances for determining the revenue requirement.

The as-filed additional revenue requirement associated with the Company's proposal is \$503,280, or \$678,271 after grossing up for income taxes, regulatory assessment fees (RAFs) and bad debt.⁴¹ This revenue requirement amount was calculated using the Company's requested weighted average cost of capital of 6.89 percent and does not include the property tax and interest expense-related income tax differentials that are incorporated into our figures. Using our approved weighted average cost of capital of 6.34 percent, and incorporating certain property- and income-related tax effects, the additional revenue requirement is \$540,015, or \$727,778, after grossing up for income taxes, RAFs, and bad debt.

We find that the substation project shall be approved; however, the full revenue requirement associated with these assets shall not be included in rates at this time as requested by FPUC. To calculate base rates at this time, the 13-month average rate base value shall be used. The additional annual revenue requirement, i.e., the difference in the associated revenue requirement based on 13-month versus year-end account balances, shall be included in customer rates as a step increase following the entire project's in-service date. Therefore, we grant FPUC

⁴⁰ Document No. 08593-2024.

⁴¹ Document No. 09266-2024.

authorization to increase its rates when all proposed substation assets have been placed into service for the benefit of FPUC's customers. FPUC has included the associated property taxes related to the acquisition and replacement of the substations and transmission assets in its calculation of the cost of these projects. We find that a portion of these costs shall be removed from the 2025 projected test year. These property taxes will be part of the subsequent step increase when these transmission and substation assets are completed and placed into service. We also find that the income tax effect related to debt interest shall also be included in the calculation.

Additionally, FPUC shall be required to file a rate calculation and associated tariff information for staff review and administrative approval following the in-service date of the substation project. The Company shall limit the total recovery amount to the incremental cost identified in this proceeding, updated to reflect our vote on cost of capital and Net Income Multiplier issues. Further, for rate derivation purposes, FPUC shall develop a factor equal to the ratio of the incremental revenue requirement associated with the project and the forecasted base revenue from electricity sales used in developing the 2025 projected test year. The factor shall then be applied uniformly to FPUC's base rates by customer class.

B. Reliability Projects

FPUC has included the costs associated with three projects in its 2025 projected test year to improve the reliability of its system: (1) the installation of a new transformer; (2) the installation of IntelliRupters; and (3) the installation of a substation loop and switches.

For the installation of a new transformer, FPUC indicated that the load growth in its Amelia Island service area has made it necessary to have three 75 MVA transformers at the step down substation to ensure reliable power for this area. The step down substation currently has two 75 MVA transformers, and one 50 MVA transformer. FPUC stated that if one of the current 75 MVA transformers were to fail, there would be instances where the remaining 50 MVA and 75 MVA transformers would not ensure reliable power to Amelia Island.⁴² Therefore, FPUC intends to replace the remaining 50 MVA transformer with another 75 MVA transformer, and sell the 50 MVA transformer once replaced. FPUC expects this project to be completed by November 2025, with a total estimated cost of approximately \$2.7 million. FPUC intends to select the suppliers and contractors selected for the previous transformer replacements at the same location based on the success and efficiency of those replacements. The cost estimate for this project was developed using the transformer cost from the manufacturer, and installation costs based on the previous replacements.

For the installation of IntelliRupters, or fault detecting devices, FPUC indicated that it intends to install such devices to detect which sections of the system have outages, and minimize outage times to customers. In response to staff's data requests, FPUC indicated that currently, an entire distribution feeder remains out of service until Company personnel can travel to the location, determine the issue, and perform switching operations to restore service to most customers.⁴³ This has contributed to FPUC's reliability indicators comparing unfavorably to

⁴² Response No. 1 in Staff's Sixth Data Request, Document No. 09794-2024.

⁴³ Response No. 10 in Staff's Twentieth Data Request, Document No. 00017-2025.

other large investor-owned utilities, especially when large sections, such as an entire distribution feeder, are tripped offline due to issues such as a tree falling on a power line or a car hitting a pole. This project would improve the reliability to customers by detecting the approximate location of the issue, and automatically isolating the impacted section.⁴⁴ FPUC expects this project to be completed by December 2025, with a total estimated cost of approximately \$750,000. The Company intends to complete this project internally which will minimize the rate impact on customers. Cost estimates for this project were developed internally with input from the equipment vendors who provided estimates on equipment and installation costs.

For the installation of a substation loop and switches, FPUC stated that this project is part of a long term project to provide more reliable backup transmission service to the substations in its Amelia Island service area. This project consists of the installation of a 69 kilovolt underground cable and seven switches at FPUC's stepdown substation. FPUC indicated that it does not have the ability to work on transmission lines while still energized and as such, at least two transmission lines feeding a substation are necessary to keep the substation energized during maintenance activities and prevent interruptions to customers served from that substation.⁴⁵

The additional transmission line and switches being installed for this project will allow FPUC to isolate and de-energize each respective transmission line during maintenance activities, which will allow the Company to keep the substation energized and ensure a continuous supply of electricity to customers served by this substation. Additionally, this project would provide backup transmission service in the event that the primary transmission line has an outage. This project would improve reliability by providing backup transmission service at the stepdown substation, and allowing maintenance to be performed without impact to customers. FPUC expects this project to be completed by May 2025, with a total estimated cost of approximately \$750,000. FPUC opted to select a contractor who has an existing contract with the Company to complete this project based on the complexities of this type of project. Cost estimates for this project were provided by the contractor.

We have reviewed these projects and find that they will allow FPUC to maintain and improve the reliability of its electric system by ensuring reliable power to its Amelia Island service area and reducing service interruptions across its entire service area. For these reasons, we approve FPUC's proposed reliability projects for inclusion in the 2025 projected test year with no adjustments.

C. Safety Projects

FPUC has included the costs associated with three projects in its 2025 projected test year to improve the safety of its system: (1) the replacement of fibercrete vaults; (2) the replacement of live front equipment; and (3) the replacement of unjacketed underground cable. FPUC intends to complete all of these projects internally, which will minimize the rate impact on

⁴⁴ FPUC is also proposing a related program, the Distribution and Connectivity Automation program, as part of its proposed storm protection plan in Docket No. 20250017-EI. This program consists of the assessment of feeder lines for the installation of feeder ties and additional self-healing equipment beginning in 2028, which when combined with the proposed fault detection equipment would allow automated fault detection and restoration processes.

⁴⁵ Response No. 10 in Staff's Twentieth Data Request, Document No. 00017-2025.

customers. Cost estimates for these projects were developed internally based on previous similar work completed by Company personnel.

For the fibercrete vaults replacement project, FPUC indicated in response to staff data requests that the fibercrete vaults under four manholes are eroding and need to be replaced.⁴⁶ These vaults are underground concrete enclosures that are used to provide a protected, accessible underground space to house and maintain Company electrical equipment. FPUC expects this project to be completed by December 2025, with a total estimated cost of approximately \$400,000.

For the live front equipment replacement project, FPUC indicated that this equipment has been in service for many years, is outdated, and is unreliable as it has been responsible for numerous outages.⁴⁷ Live front equipment is electrical equipment containing uninsulated, energized electrical connections, which requires workers to use extra safety precautions to avoid direct contact with electricity. FPUC stated that due to this equipment being uninsulated, it poses a safety threat to workers, and is vulnerable to wildlife contact and contamination. Therefore, FPUC intends to replace 10 live fronts with traditional pad-mounted dead front equipment. Pad-mounted dead front equipment is electrical equipment installed on a concrete pad containing insulated, energized electrical connections, which ensures that there are no exposed connections. This equipment provides safety protection and eliminates the risk of exposure to wildlife or foreign objects due to being insulated. FPUC expects this project to be completed by December 2025, with a total estimated cost of approximately \$720,000.

For the unjacketed underground cable project, FPUC indicated that this equipment is unreliable and at the end of its useful life.⁴⁸ Unjacketed underground cable is a cable with insulated high voltage wires, but no outer protective layer to shield the conductors. According to FPUC, the unjacketed underground cable uses a concentric neutral consisting of several bare copper conductors that are wrapped around the cable. The concentric neutral is uninsulated and therefore exposed to the elements. As such, the concentric neutral deteriorates over time, which impacts the reliability and safe operation of the equipment it is connected to. Therefore, FPUC intends to replace unjacketed underground cable with new jacketed underground cable, which provides insulation for the concentric neutral and thus protects it from exposure to the elements, resulting in improved reliability and safety of the equipment it is connected to. FPUC expects to replace approximately 7,000 feet of unjacketed underground cable by December 2025, with a total estimated cost of approximately \$500,000.

Having reviewed these projects, we find that they are necessary to improve the safety and reliability of FPUC's system and to reduce risk to life and property. Further, we find that the associated costs are reasonable. For these reasons, we approve FPUC's proposed safety projects for inclusion in the 2025 projected test year with no adjustments.

D. Security Cameras

⁴⁶ Response No. 25 in Staff's Sixth Data Request, Document No. 09794-2024.

⁴⁷ Response No. 11 in Staff's Sixth Data Request, Document No. 09794-2024.

⁴⁸ *Id.*

FPUC's requested security camera project includes the installation of 27 multi-sensor and dual cameras used to monitor and record activities in specific areas.⁴⁹ Of the 27 cameras, five will be installed at the Fernandina Beach Operation Center and three at the Marianna Operation Center. The remaining 19 cameras will be installed amongst FPUC's seven substations.⁵⁰ The control house at each location will also be equipped with card readers, electric strike door locks, door contacts, request to exit motion, and communications equipment. FPUC requested a total capital cost of \$326,430 and annual O&M expense of \$63,024 for this project. The O&M expense would include Cloud storage, on premises video retention for each site, and the video management system. FPUC began installing cameras in November 2024 in Fernandina Beach and will then move to Marianna. Installations are expected to be completed in the first quarter of 2025.⁵¹ The vendor for this project is Advantech. Advantech won a bid for the role of security integrator for Chesapeake in 2017 and the Company has continued to use them for similar projects since that time.

FPUC witness Haffecke testified that cameras are being added at substations and offices to provide additional security for FPUC's equipment, better protect the public, and help deter theft that could lead to potential reliability issues. Additionally, FPUC indicated that this project is also needed to align with the North American Electric Reliability Corporation's Critical Infrastructure Protection standards. For these reasons, we approve the proposed security camera project with a capital cost of \$326,430 and annual O&M expense of \$63,024 for the 2025 projected test year.

E. Two-way Communication System

FPUC's requested two-way communication system is a system that allows employees to communicate by radio rather than cellular service. Witness Haffecke testified that previously the Company did not have a two-way communication system and relied on cellular telephones to communicate between its operation centers and field crews. Difficulties appear when cell towers are damaged and cellular communication is lost, especially during severe weather.⁵² The Company originally requested to recover capital costs of \$1.3 million for this project with no associated O&M expenses. However, based upon updated information and bids, the estimated capital costs for this project is \$326,430 with no associated O&M expenses, which results in a rate base reduction of \$940,711 from the Company's original request.⁵³

FPUC states that the two-way communication system will improve safety for the Company's employees and the public. This system will also help expedite outage restoration times by allowing dispatchers and management to guide crews directly to outages and assist with switching activities. Furthermore, employees will have the ability to contact each other when additional materials are needed. A reliable communication system for field crews helps ensure

⁴⁹ Response No. 4 in Staff's Tenth Data Request, Document No. 09893-2024.

⁵⁰ Response No. 4 in Staff's Tenth Data Request, Document No. 09893-2024.

⁵¹ Response No. 4 in Staff's Tenth Data Request, Document No. 09893-2024.

⁵² Witness Haffecke Direct Testimony, Page 15, Lines 13-16, Document No. 08582-2024.

⁵³ Document No. 00570-2025, filed January 30, 2025, in Docket No. 20240099-EI.

that FPUC's employees working on an affected circuit are in a safe position before energizing the circuit. Currently, restoration activities are performed by visual confirmation when cellular service is not available, which requires employees to physically go see impacted circuits.⁵⁴

The Company received two bids for the radio and end-user equipment, one of which is from Radio One. A final vendor has not yet been selected. The \$326,430 of capital costs for this project is based off of the Radio One bid, which contemplates Motorola equipment, the anticipated amount for additional antennas and poles, installation, and Federal Aviation Administration regulatory compliance. FPUC stated it commissioned and just recently received the completed radio propagation study to ensure reliable radio coverage would be available over the entire electrical service territory.⁵⁵ The two-way communication system is planned to go in service June 2025. The associated property taxes related to the adjusted proposed two-way communication system have been included by FPUC in the projected 2025 projected test year. This is not appropriate and we find that these associated property taxes shall be removed.

We find that the proposed two-way communication system will improve safety for field workers due to the ability to communicate with other personnel even when cellular service is not available. System efficiency will also increase due to no longer needing visual confirmation of damaged circuits if cellular service is not available. In developing its project cost for the two-way communication system the Company included associated property taxes. These costs in proportion to the adjusted cost of the two-way communication system shall be removed from the 2025 projected test year. For these reasons, we find that FPUC's proposed two-way communication system, with a capital cost of \$326,430 shall be included in the 2025 projected test year. This results in a reduction to rate base of \$939,615 and a reduction to depreciation expense of \$187,357.

F. New Customer Information System

FPUC's requested CIS went live on August 26, 2024, and was capitalized on October 1, 2024. The total capital cost for the system is \$6,912,623. FPUC witness Estrada stated that the CIS project will replace two existing billing and payment platforms that are at end-of-life expectancy, with one streamlined system with an automated billing and invoicing process. The new system will allow customers to experience improvements with timing and accuracy of billing. The number of customers who receive paperless bills and make electronic payments has the potential to increase. Once entered into the system, meter readings are automatically reviewed, allowing identification of outliers such as unexpected high or low readings, and if necessary, create an exception.⁵⁶ This would allow for a process where the system will detect missing or unusual data that can be reviewed and adjusted, if necessary, prior to going out to customers. This project helps with reducing the manual processing time, which allows bills to be prepared efficiently. By the end of 2025, as part of this project, the customer self-service portal will allow residential and commercial customers to view and download their bills, view usage

⁵⁴ Witness Haffecke Direct Testimony, Page 16, Lines 1-5, Document No. 08582-2024.

⁵⁵ Response No. 1 in Staff's 23rd Data Request, Document No. 10388-2024.

⁵⁶ Response No. 2 in Staff's Tenth Data Request, Document No. 09893-2024.

and payment history, make payments at any time, and have the ability to start and stop service. This foundational system provides a platform for future enhancements.

FPUC witness Gadgil stated that the CIS is based on the Systems, Applications, and Products (SAP) platform, a technology platform for enterprise and business applications. The new SAP platform allows better scheduling and real-time updates, resulting in reasonable and reliable service for FPUC customers. With cybersecurity threats increasing, it is imperative to secure customer data. The new SAP solution will incorporate security measures to protect sensitive information and ensure compliance with industry standards and regulations. The new system will provide data management capabilities to ensure the integrity and confidentiality of customer information to build greater trust and confidence among customers.⁵⁷ Monitoring that enables the Company to identify and address any potential compliance deviations, and ensures that the standards of data protection and cybersecurity are consistent.

For this project, FPUC selected TMG for the system assessment and procurement process and selected Ernst & Young for the analysis of system replacement alternatives because both were priced reasonably and had relevant experience with Utility billing system projects and related software implementation. Throughout the implementation, other vendors were also utilized to complete specialized tasks associated with this project. For example, KPMG performed quality assurance checks and Storm Runner conducted performance testing. During the alternative assessment phase of this project evaluation, each potential option was evaluated against a set of risk factors, such as execution, reliability and security, and ongoing operations. After consideration of the system replacement alternatives and associated risk factors, FPUC ultimately chose the CIS system proposed in this issue. The cybersecurity and continuous monitoring components of the system result in an annual O&M expense of \$356,083.⁵⁸

We agree that CIS would replace end of life software and provide billing benefits to customers on one streamlined system. Furthermore, the cyber security components through the SAP platform of the CIS are necessary and reasonable considering the Company's increasing amount of customer data through its various platforms along with the sophistication of cyber security threats. Therefore, we approve the proposed project with capital cost of \$6.9 million and O&M expense of \$356,083, for the 2025 projected test year without any adjustments.

G. Non-utility Activities

In accordance with Order No. PSC-2008-0327-FOF-EI, and as shown on MFR Schedule B-2, the Company removed a portion of electric assets shared with other divisions from Plant in Service in the amount of \$7,684. FPUC also made an associated adjustment to reduce accumulated depreciation by \$1,954.⁵⁹ The Company stated "the only non-utility plant was related to five vehicles used by employees that work on other business units. Any payroll or

⁵⁷ Witness Gadgil Direct Testimony, Page 8, Lines 8-22, Document No. 08588-2024.

⁵⁸ Response No. 4 in Staff's Tenth Data Request, Document No. 09893-2024.

⁵⁹ Order No. PSC-2008-0327-FOF-EI, issued on May 19, 2008, in Docket No. 20070300-EI, *In re: Review of 2007 Electric Infrastructure Storm Hardening Plan filed pursuant to Rule 25-6.0342, F.A.C., submitted by Florida Public Utilities Company*; and Docket No. 20070304-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

costs related to those employees were charged directly to those non-regulated business units.”⁶⁰ FPUC witness Napier also stated in her direct testimony that “[t]he Company has removed plant and its reserve for a portion of the assets used and/or shared with other non-utility operations, consistent with the treatment approved by Order No. PSC-2008-0327-FOF-EI.”⁶¹ Since the Company has made the above adjustments as previously ordered us, we find that no further adjustments are necessary.

H. Plant in Service

In its filing on MFR Schedule B-3 (2025), the Company recorded a 13-month average Plant in Service balance of \$227,496,601. Additionally, the Company recorded an allocated 13-month average Plant in Service balance of \$1,761,909. This allocated portion consists of \$269,511 from the Company’s Florida common plant, and \$1,492,397 from its corporate common plant as shown on MFR Schedule B-8 (2025).

As shown on MFR Schedule B-3 (2025), the Company reduced Plant in Service by \$307,918 to remove the 13-month average balance of customer advances for construction.

The Company also made an adjustment to decrease Plant in Service by \$7,684 by removing non-utility plant per Order No. PSC-2008-0327-FOF-EI. Additionally, adjustments were made removing capitalized investments in the Storm Protection Plan (SPP) Cost Recovery Clause from Plant in Service. These adjustments are shown below in Table 12.

Table 12
Adjustments to Remove Capitalized Investments in SPP Cost Recovery Clause

Description	Amount
Acct. 355S Poles & Fixtures	\$2,121,968
Acct. 364S Poles, Towers & Fixtures	9,710,781
Acct. 365S Overhead Conductors & Devices	11,324,543
Acct. 366S Underground Conduits	<u>989,797</u>
Total SPP Adjustments	<u>\$24,147,089</u>

Source: MFR Schedule B-8 (2025).

Additionally, the Company increased Plant in Service by \$11,472,643 to record substation additions in 2025 as if they were in service for a full year, as described in FPUC witness Haffecke’s direct testimony. FPUC witness Haffecke stated “[a]llowing the Company to use a full-year approach would reduce the need for additional rate relief shortly after implementation of rates resulting from this rate case.”⁶² As discussed above, we have removed the Company’s increase of \$11,472,643. Further, we have made an adjustment to the two-way communication system reducing Plant in Service by \$939,615.

⁶⁰ Response No. 1 in Staff’s Sixteenth Data Request, Document No. 10111-2024.

⁶¹ Witness Napier Direct Testimony, Page 11, Lines 2-4, Document No. 08583-2024.

⁶² Witness Haffecke Direct Testimony, Page 12, Lines 5-6. Document No. 08582-2024.

Based on the adjustments described above and the calculations provided in the Company’s MFRs, we find that the appropriate level of Plant in Service for the 2025 projected test year is \$203,856,204 as shown in Table 13.

Table 13
Summary of Plant Adjustments

Description	Amount
Plant in Service	\$227,496,601
Allocated Florida Electric Division Common Plant in Service	269,511
Allocated Corporate Common Plant in Service	1,492,397
Removal of Customer Advances-Construction	(307,918)
Adjustment to remove non-utility plant	(7,684)
Adjustment to remove SPP	(24,147,089)
Adjustment by Company to include full-year of substation investment	11,472,643
Staff adjustment to remove full-year of substation investment	(11,472,643)
Adjustment for two-way communication system	(939,615)
Total Adjusted Plant in Service	<u>\$203,856,204</u>

Sources: MFR Schedules B-3 (2025), B-8 (2025), and staff calculations.

I. Accumulated Depreciation

Accumulated depreciation essentially tracks asset value reduction over time, thus assisting to provide a real-time understanding of the value associated with the Company’s balance sheet. Accounting for accumulated depreciation helps to ensure that the Company’s financial statements reflect the value of its assets and to provide an accurate view of its financial health.

The Company’s as-filed level of accumulated depreciation for the 2025 test year is \$77,701,596 per books. After accounting for FPUC’s proposed adjustments, the projected 2025 test year level of accumulated depreciation is \$80,961,538.⁶³ Incorporating the changes made to depreciation expense discussed below, as well as amendments made to the reserve balances of Account 391.1 - Computer and Peripheral and Account 391.2 - Computer Hardware, the amended jurisdictional adjusted level of accumulated depreciation for the 2025 test year is \$81,100,045.⁶⁴ We have also adjusted \$337,844 from the Company’s request related to the approved recovery of the substation assets discussed above. Additionally, we have adjusted accumulated depreciation by \$87,365 associated with the Company’s proposed two-way

⁶³ Document No. 08593-2024.

⁶⁴ Document No. 09739-2024.

communication system discussed above.⁶⁵ Thus, the jurisdictional adjusted level of accumulated depreciation for the 2025 test year is \$80,674,837.

Based on the above, we approve an accumulated depreciation level of \$80,674,837 for the 2025 projected test year.

J. Working Capital

In its filing, the Company recorded a 13-month average net Working Capital balance of \$12,995,015 for its consolidated electric division, and a 13-month average net Working Capital balance of \$5,272,225 for its common allocation. Combined, the Company recorded a 13-month average Working Capital balance of \$18,267,240.

In our review, we discovered a debit balance of \$6,482,906 in the Company’s allocated accrued pension and post medical account. The Company explained its reasoning for a debit balance for these expenses as follows:⁶⁶

The amount in the electric business unit represents the net benefit plan liability of over funded status. The liability continues to decline over time based on the actuarial data. The Company expects benefit payments for both the pension plan and the OPRB plan will continue to decline over time. Although both plans are frozen for new participants, the assets continue to perform at a level that enables them to meet future obligations and reduce the Company’s requirement to have to make contributions to cover any shortfalls.

The Company’s net Working Capital is detailed below in Table 14.

Table 14
13-Month Average Working Capital Balance

Description	Amount
Consolidated Electric Division Assets	\$29,581,730
Less: Consolidated Electric Division Liabilities	(16,586,715)
Net Working Capital (Consolidated Electric Division)	<u>\$12,995,015</u>
Florida Common Division Allocation Assets	\$25,665
Less: Florida Common Division Allocation Liabilities	(1,236,346)
Allocated accrued pension and post medical account	<u>6,482,906</u>
Net Working Capital (Florida Common Division Allocation)	<u>\$5,272,225</u>

⁶⁵ Document No. 00570-2025.

⁶⁶ Response No. 2 in Staff’s Sixteenth Data Request, Document No. 10111-2024, Document No. 10111-2024.

Total Net Working Capital	<u>\$18,267,240</u>
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Sources: MFR Schedules B-3 (2025) and B-3A (2025).

As shown on MFR Schedule B-2 (2025), the Company reduced Working Capital balance by \$1,331,206 to remove the deferred rate case expense. While FPUC witness Napier argued in testimony that the Company believes it should be allowed to include one-half of the deferred rate case expense, the full amount was removed in this filing.

FPUC also reduced Working Capital by \$3,769,633 to remove storm recovery costs which are interest-earning. Additionally, the Company further reduced Working Capital by \$398,941 to remove an under-recovery which is interest-earning in its Storm Protection Plan.

Table 15
Working Capital Calculation

Description	Amount
Total Net Working Capital	\$18,267,240
Removal of deferred rate case expense	(1,331,206)
Removal of interest-earning storm recovery costs	(3,769,633)
Removal of interest-earning under-recovery in SPP	(398,941)
Total Working Capital	<u>\$12,767,460</u>

Sources: MFR Schedules B-2 (2025), B-3 (2025) and B-3A (2025).

Based on the calculations above and detailed in Table 15, we approve a Working Capital balance for the 2025 projected test year of \$12,767,460.

K. Construction Work in Progress

Construction work in progress (CWIP) is an accounting classification that includes the costs of ongoing construction projects in rate base. In its filing, MFR Schedule B-3 (2025) the Company recorded a 13-month average CWIP of \$12,869,084.

The Company removed CWIP related to the SPP Clause, which resulted in a reduction (of CWIP) of \$3,827,550. Additionally, the Company reduced CWIP by \$731,263 by removing the amounts which are eligible for available funds used during construction (AFUDC) under Rule 25-6.0141, F.A.C. Finally, FPUC removed CWIP associated with the substation additions in 2025 as if they were transferred to plant for a full year as discussed above. This adjustment resulted in a reduction to CWIP of \$6,331,558.

As discussed above, we do not find it appropriate to include the full-year calculation for the substations in Plant in Service, and therefore returned \$6,331,558 to CWIP associated with the substations. Additionally, we made an adjustment reducing Plant in Service for the two-way communication system. As such, a corresponding adjustment reducing CWIP by \$88,462 is appropriate.

In total, the Company reduced CWIP by \$10,890,371. We have made a net adjustment increasing CWIP by \$6,243,096 and therefore, we find that the appropriate level of CWIP for the 2025 projected test year is \$8,221,809.

L. Property Held for Future Use

Property Held for Future Use refers to land, structures, or equipment owned by a utility that is currently not in use but is being held in anticipation of future needs. On MFR Schedule B-15, FPUC stated that it has no Property Held for Future Use for the 2025 projected test year.⁶⁷ Therefore, we find that the appropriate level of Property Held for Future Use shall be \$0.

Rate base for the 2025 projected test year is a fall-out amount based on our decisions on the factors discussed above. Based on our decisions as stated above, we find that the appropriate level of rate base for the 2025 projected test year is \$144,170,635 as detailed in Table 16 below.

Table 16
Commission Approved Rate Base

Section	Description	Amount
H	Plant in Service	\$203,856,204
I	Accumulated Depreciation	(80,674,837)
J	Working Capital	12,767,460
K	Construction Work in Progress	<u>8,221,809</u>
Total		<u>\$144,170,635</u>

Source: Staff calculations.

V. Capital Structure

A. Accumulated Deferred Taxes

FPUC requested a total accumulated deferred income tax (ADITs) balance of \$13,206,708, be included in the 2025 projected test year capital structure, which is presented on MFR Schedule D-1a (Supplement).⁶⁸ FPUC witness Crowley explains that FPUC's regulatory capital structure reflects similar levels of stability within the debt and equity components. Across other capital items, for example, accumulated deferred income taxes and regulatory tax liability attributable to electric operations, FPUC has experienced some variability over years 2023 to 2025. In the case of deferred income tax, this balance declines from approximately \$22 million in 2023 to approximately \$13 million in 2025.

In Audit Finding 4, our staff determined that the appropriate credit ADIT balance associated with the requested rate case expense was not properly included in the 2025 projected test year capital structure.⁶⁹ On MFR Schedule C-10, FPUC projected a total rate case expense

⁶⁷ Document No. 08593-2024.

⁶⁸ Document No. 08596-2024.

⁶⁹ Document No. 10324-2024.

of \$1,530,907. This cost was spread over a four-year amortization period which yields a test year amortization expense of \$382,727.⁷⁰ The unamortized rate case expense for the remaining three years is \$1,148,180 which creates an ADIT credit of \$291,009. FPUC's effective tax rate of 25.345 percent is multiplied by the unamortized balance of rate case expense to calculate the ADIT credit. Making a specific adjustment to increase the ADIT balance by \$291,009 to reflect our adjustment, the ADIT balance became \$13,497,717. However, we ultimately ordered rate case expense to be recovered over five years. Thus, we further increased the capital structure ADIT balance by \$19,398, to account for this change. This results in an ADIT balance for the 2025 test year capital structure of \$13,517,115.

B. Customer Deposits

In MFR Schedule D-1a (Supplement), FPUC presented its 2025 projected test year capital structure.⁷¹ The capital structure is based on a 13-month average reflecting a customer deposit balance in the amount of \$4,001,097. We have confirmed that the regulatory capital structure contained the appropriate amount and confirmed that customer deposits should be at a cost rate of 2.20 percent.

We have reviewed MFR Schedule D-6, and confirmed that the calculation of interest associated with customer deposits complies with the requirements set forth in Rule 25-6.097(5)(a), F.A.C.⁷² Accordingly, we find that the amount and cost rate for customer deposits approved for the 2025 projected test year capital structure is \$4,001,097 at a cost rate of 2.20 percent.

C. Short-term Debt

As presented in MFR Schedule D-1a, and MFR Schedule D-3, FPUC requested a short-term debt cost rate of 5.81 percent with a jurisdictional amount of \$7,255,028. FPUC obtains its short-term debt from its parent company Chesapeake Utilities Corporation (CUC). CUC has a syndicated credit facility revolver for short-term borrowings with six participating banks. CUC's Revolver is currently comprised of a multi-tranche short-term borrowing facility with a total capacity of \$450 million. According to FPUC witness Russell, CUC's Revolver provides cost-effective competitive financing and benefits to FPUC by providing short-term capital availability for Company projects during construction, before obtaining permanent long-term financing once the projects are in service.

As of June 30, 2024, the pricing for CUC's short-term borrowing includes an unused commitment fee of 0.20 percent and an interest rate of 0.90 percent over the Secured Overnight Financing Rate (SOFR), plus a 0.10 percent credit adjustment. The current SOFR rate as of December 11, 2024, was approximately 4.67 percent. Witness Russell explained CUC's pricing is very competitive in the market and is comparable to pricing available to many publicly traded electric utilities that also have investment grade debt.

⁷⁰ Document No. 08594-2024.

⁷¹ Document No. 08596-2024.

⁷² *Id.*

The amount of short-term debt in the projected test year capital structure is based on CUC's investor supplied capital structure, which includes a ratio of short-term debt of 5.65 percent. After reconciling the capital structure to the rate base amount approved above, the amount of short-term debt in the jurisdictional capital structure is \$6,905,103. Based on the above, we find the appropriate amount for short-term debt to include in the capital structure for the 2025 projected test year is \$6,905,103 at a cost rate of 5.81 percent.

D. Long-term Debt

In its initial filing, FPUC presented its 2025 projected test year capital structure based on a 13-month average consisting of long-term debt in the jurisdictional adjusted amount of \$56,888,413 at a cost rate of 4.51 percent. These values are shown on MFR Schedule D-1a (Supplement). FPUC does not issue its own debt and receives all its capital funding from its parent company CUC. FPUC uses CUC's capital structure and cost rates as CUC provides all investor sources of capital to FPUC, which benefits FPUC through a lower cost of capital.

FPUC presented two calculations for its cost of long-term debt. The calculation using the traditional method to calculate the embedded cost of debt is presented in MFR Schedule D-4a. The traditional calculation was based on CUC's entire amount of long-term debt outstanding, reflecting a cost rate of 5.21 percent. The long-term debt cost rate requested by the Company is presented in MFR Schedule D-4a (Supplement). FPUC's cost rate of 4.51 percent includes adjustments to remove a portion of the debt associated with CUC's acquisition of Florida City Gas (FCG).

As explained by witness Russell, only 21 percent of the six issuances of long-term debt issued in November 2023 is assigned to FPUC for rate making purposes. The coupon rates on the six Senior Notes listed in MFR Schedule D-4a range from 6.39 percent to 6.73 percent which are significantly higher than coupon rates on previous long-term debt issuances. The six Senior Notes total \$550 million and were issued by CUC in November 2023, and were predominately used to finance the acquisition of FCG. Three of the seven notes total \$300 million and have maturities of less than seven years. FPUC anticipates that both short-term and long-term interest rates will decline from current levels, and in the future, it will be in a better position to replace the higher cost debt with lower cost longer term debt. FPUC requested that the Commission use MFR Schedule D-4a (Supplement) as it includes only 21 percent of the six Senior Notes relating to the overall funding operations for FPUC, resulting in a lower cost of long-term debt for its customers. This calculation effectively removes approximately \$500,000 from FPUC's revenue requirement and lowers the Weighted Average Cost of Capital (WACC) by 26 basis points. FPUC requested that if the methodology used to calculate the long-term debt cost rate of 4.51 percent as presented in MFR Schedule D-4a (Supplement) is not approved, that we approve the capital structure provided in in MFR D-1a which includes a cost rate of 5.21 percent.

The long-term debt of CUC has an investment credit rating of NAIC-2B issued from the National Association of Insurance Commissioners (NAIC). This assigned rating indicates high quality obligations with a low credit risk and would be equivalent to Standard & Poor's, and Moody's credit ratings of BBB and Baa2. According to FPUC witness Russell, U.S. Treasury rates for 3-, 5-, 7-, and 10-year durations are currently at elevated levels, but are just slightly below the rate presented on MFR Schedule D-4a (Supplement). If CUC were to issue any new

long-term debt, the rate would include a spread that supports the CUC's NAIC-2B rating. FPUC explained that the issuances of Senior Notes 28 and 29 in the 2025 test year will be used to fund capital construction growth with the intent of maintaining its capital structure balance.⁷³ FPUC estimated the coupon rate of 5.75 percent for Senior Notes 28 and 29 by estimating the spread between the last-twelve month average for the 10-year and 20-year U.S. Treasury rates and the BBB Corporate Bond Index. Mathematically, the Company calculated the spread between the average of the 10-year and 20-year U.S. Treasury Bond yields and the average of the 10-year and 20-year BBB Corporate Bond yields. We find that the methodology of using the U.S. Treasury Bond yields and adding the Corporate Bond yield spread is reasonable and consistent with our past practice.⁷⁴

After reviewing the Company's assumptions and calculations for the requested cost rate for long-term debt, we find that the cost rate of 4.51 percent is very reasonable. In comparison, the 2025 forecasted yields on 10-year and 30-year U.S. Treasury Bonds are 4.40 percent and 4.70 percent, respectively.⁷⁵ Based on the above, the requested cost rate of 4.51 percent is reasonable and benefits the customers of FPUC in comparison to the unadjusted cost rate of 5.21 percent. After reconciling the capital structure to the rate base amount previously approved, we find that the amount of long-term debt for the 2025 projected test year is \$54,144,567 at a cost rate of 4.51 percent.

E. Equity Ratio

In its filing, FPUC requested a projected test year capital structure consisting of an equity ratio of 50.04 percent based on investor-supplied capital for ratemaking purposes. FPUC witness Russell explained the Company does not issue debt or equity directly and as a result, any funding needs for FPUC are provided by its parent company, CUC. With the original source of funding being derived from the equity issuances or debt financing at the parent level, FPUC employs CUC's capital structure to determine its rate of return.

Witness Russell explained the Company's capital structure at the end of the 2025 projected test year consists of common equity of 50.04 percent, long-term debt of 44.31 percent, and short-term debt of 5.65 percent, based on investor sources. Witness Russell affirmed an equity ratio of 55 percent is the midpoint of the target equity ratio range of 50 to 60 percent approved by CUC's board of directors and the Corporation strives to achieve that target range. Furthermore, Exhibit No. NTR-1, Schedule 1 shows CUC's historical equity ratios for calendar years 2014 through 2023. As explained by witness Russell and as the schedule reflects, CUC has consistently achieved its targeted equity range with limited deviations. Upon review, the average equity ratio from 2014 through 2023 is 50.22 percent, which is consistent with the forecasted equity ratio of 50.04 percent requested by FPUC for the 2025 projected test year.

⁷³ Document No. 10367-2024.

⁷⁴ 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.*, and Order No. PSC-2025-0038-FOF-EI, issued February 3, 2025, in Docket No. 20240026-EI, *In re: Petition for rate increase by Tampa Electric Company*.

⁷⁵ Blue Chip Financial Forecasts, Vol. 44, No. 2, issued January 31, 2025.

The Commission-authorized equity ratios for Florida’s investor-owned electric (55.53 percent) and natural gas (53.57 percent) utilities average 54.30 percent. FPUC’s requested equity ratio for the projected test year is within the range of equity ratios of the aforementioned utilities, which are summarized below in Table 17.

Table 17
Florida Investor-Owned Electric and Natural Gas Equity Ratios

Company	Order Number	Issued	Equity Ratio
Duke Energy Florida, LLC	PSC-2024-0472-AS-EI	11/12/2024	53.00%
Florida City Gas	PSC-2023-0177-FOF-GU	06/09/2023	59.60%
Florida Power & Light Company	PSC-2021-0446-S-EI	12/02/2021	59.60%
FPUC (Natural Gas Division)	PSC-2023-0103-FOF-GU	03/15/2023	55.10%
Peoples Gas System, Inc.	PSC-2023-0388-FOF-GU	12/27/2023	54.70%
Sebring Gas System, Inc.	PSC-2020-0047-PAA-GU	02/03/2020	38.43%
St. Joe Natural Gas Company, Inc.	PSC-2025-0035-PAA-GU	01/30/2025	60.00%
Tampa Electric Company	PSC-2025-0038-FOF-EI	02/03/2025	54.00%
Average			54.30%

Source: Staff Analysis.

Witness Russell confirmed that just prior to the acquisition of Florida City Gas (FCG), the equity ratio for CUC was approximately 53 percent as of September 30, 2023. CUC issued debt to partially fund its acquisition of FCG, which lowered its equity ratio below 50 percent. Witness Russell affirmed that since the acquisition, CUC has moved this ratio from approximately 47 percent to above 48 percent and is on path to restore its equity ratio within the target range (in the test year) and proceed towards the midpoint.

FPUC used CUC’s capital structure in its 2014 electric rate case which included an equity ratio of approximately 58 percent.⁷⁶ Additionally, FPUC employed CUC’s capital structure for its 2022 natural gas rate case in which we approved an equity ratio of 55.10 percent.⁷⁷ Accordingly, the use of CUC’s capital structure to establish FPUC’s regulatory capital structure is consistent with our prior decisions for both the Company’s electric and gas utilities.

Based on our analysis of this issue, FPUC’s requested equity ratio of 50.04 percent, based on investor sources, for the 2025 projected test year is reasonable. After reconciling the capital

⁷⁶ Order No. PSC-2014-0517-S-EI, issued September 29, 2014, in Docket No. 20140025-EI, *In re: Application for rate increase by Florida Public Utilities Company.*

⁷⁷ 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 - Fort Meade, and Florida Public Utilities Company - Indiantown Division.*

structure to the rate base amount, we find that the amount of common equity that shall be included in the 2025 projected test year capital structure is \$61,154,478.

F. Return on Equity

The return on common equity (ROE) is the cost of common equity included in a company's regulatory capital structure used to establish a revenue requirement. A reasonable ROE for a regulated company requires determining the market-based cost of capital. The market-based cost of capital for a regulated firm represents the return investors could expect from other investments, while assuming no more and no less risk. In other words, the authorized ROE should be equivalent to investors' required return to invest in FPUC. FPUC's current authorized ROE is 10.25 percent and was last set in 2014 through a settlement with the Office of Public Counsel.⁷⁸ In the instant case, FPUC requested an ROE of 11.30 percent based on the testimony of witness Crowley. Witness Crowley's ROE models are largely based on historical financial and market data from 2021 through 2023, and in our opinion, do not reflect expected market conditions or investor required equity returns. To test the reasonableness of witness Crowley's ROE model analysis, we performed our own ROE analysis using more recent market data and forecasted interest rates and derived an ROE of 10.15 percent.

1. Legal Standard

The U.S. Supreme Court *Hcpe* and *Bluefield* decisions established standards for setting a fair rate of return for equity investment in utilities providing service to the public. Under the *Hcpe* 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 company, support reasonable credit quality, and allow a company to raise capital at reasonable costs and terms.⁷⁹ The *Bluefield* decision stated in pertinent part that:

A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

⁷⁸ Order No. 2014-0517-S-EI, issued September 29, 2014, in Docket No. 20140025-EI, *In re: Application for rate increase by Florida Public Utilities Company*.

⁷⁹ *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*, 262 U.S. 679, 692 (1923) (*Bluefield*) and *Federal Power Comm'n v. Hcpe Natural Gas Co.*, 320 U.S. 591, 603 (1944) (*Hcpe*)

Based on the *Bluefield* decision, a reasonable ROE is also based on the expectation that the company's costs reflect efficient and economical management, and the ROE will support its credit standing and access to capital, but will not be in excess of this level. Also, the *Bluefield* decision recognizes that a reasonable ROE will change based on economic market conditions and investment opportunities.

2. Proxy Groups

Because FPUC is not publicly traded and does not issue publicly traded equity securities, a group of publicly traded companies that have comparable risk characteristics to FPUC must be used as a proxy group to which cost of equity models are applied to determine the required ROE. Witness Crowley used three separate proxy groups in his analysis: 15 mid-size electric companies, 6 natural gas companies, and 13 small non-utility companies. The 15 electric companies have market capitalization values from \$1.0 billion to over \$20 billion.⁸⁰ In comparison, FPUC's parent company, Chesapeake Utilities Corporation's (CUC) market capitalization is \$2.9 billion. CUC is primarily a gas distribution company with a net plant of \$2.456 billion. Only \$143.513 million or 6.0 percent of CUC's \$2.456 billion net plant is for electric distribution. FPUC contributed \$99.5 million to CUC total revenues of \$670.604 million as of December 31, 2023. The proportion of revenue from FPUC to the total for CUC is 14.83 percent ($\$99.5\text{M} \div \$670.6\text{M} = 14.83\%$). Based on FPUC's percentage of revenue contribution to CUC, FPUC's estimated market capitalization would be \$430 million at CUC's stock price of \$126.44 per share ($14.83\% \times \$2.9 \text{ billion} = \430 million). FPUC's market capitalization would be less than half of the smallest electric company in witness Crowley's proxy group, which is Unitil Corporation with a market capitalization of \$970 million.

3. Mid-Size Electric Company Proxy Group⁸¹

Witness Crowley opined that it is virtually impossible to select a sizeable set of electric companies that are exclusively retail electric companies, and therefore, some of the 15 electric companies are also engaged in non-electric retail business lines including natural gas, albeit not a significant portion. We determined that all of the companies in the electric and gas proxy groups obtain over 65 percent of their revenues from regulated operations with the exception of Otter Tail Corporation (34 percent) and Southwest Gas Holdings, Inc. (47 percent). These latter two companies are therefore not comparable to FPUC, all of whose revenues are regulated.

For the electric proxy group, one of witness Crowley's selection criteria was consistent quarterly dividends and positive long-term earnings growth forecasts from at least two sources. Hawaiian Electric is no longer paying dividends due to its financial position resulting from the fires in Lahaina, Hawaii. Unitil Corporation has limited forecasted earnings and dividends making forward-looking market data unavailable. Based on the discrepancies between witness Crowley's proxy group selection criteria and the characteristics or lack of market data for

⁸⁰ Market Capitalization is the stock price multiplied by the number of shares of common stock outstanding.

⁸¹ ALLETE, Inc., Alliant Energy Corporation, Black Hills, Centerpoint Energy, Inc., Evergy, Inc., Hawaiian Electric Industries, Inc., IDA CORP, Inc., MGE Energy, Inc., Northwestern Energy Group, OGE Energy Corp., Otter Tail Corporation, Pinnacle West Capital Corporation, PNM Resources, Inc. Portland General Electric Company, Unitil Corporation.

Hawaiian Electric, Otter Tail Corporation, and Unitil Corporation, these companies should not have been included in witness Crowley's electric proxy group. In addition, Alliant Energy, CenterPoint Energy, Inc. and Evergy, Inc. are considered large-capitalization companies and are significantly larger than CUC, and especially FPUC. These three utilities represent 47 percent of the weighted average of witness Crowley's ROE model results. While we do not disagree with weighting the results of the cost of capital models, witness Crowley included three large cap companies that biased the results of his analysis toward the three companies that are significantly larger than FPUC.

4. Natural Gas Distribution Company Proxy Group⁸²

Witness Crowley also used a proxy group of six natural gas companies that have market capitalizations ranging from \$1.66 billion to \$15 billion. Witness Crowley did not perform a quantitative analysis of FPUC's risk characteristics to that of his gas proxy group but explained that qualitatively, FPUC is similar to a natural gas distribution company. FPUC explained that because natural gas companies deliver services through a distribution pipeline to individual customer delivery points through a meter, the risk of the gas proxy group closely compares to that of FPUC's electric operations.⁸³ FPUC also stated that both FPUC and the companies in the gas proxy group provide essential services required for a functioning economy; own and operate substantial, long-lived capital infrastructure; and operate in a regulated utility environment.⁸⁴ Thus, witness Crowley believes gas utilities face many of the same financial, regulatory, and cybersecurity risks as electric utility operations, like those of FPUC.⁸⁵ FPUC further explained that all else equal, the gas proxy companies would be less risky because they do not have the same exposure to weather risk and could bias the cost of equity estimate downward.⁸⁶ We agree that regulated natural gas distribution companies can be used as a proxy for FPUC. However, Southwest Gas Holdings, Inc. obtains less than 50 percent of its total revenue from regulated operations and is not comparable to FPUC.

5. Non-Regulated Company Proxy Group⁸⁷

Witness Crowley selected 13 non-regulated companies with market capitalizations less than \$2 billion as his Non-Regulated Proxy Group. Witness Crowley explained that some of the non-regulated companies are financed exclusively with equity. Such a company would not have a financial risk comparable to that of FPUC which is requesting an equity ratio of 50.04 percent and would not be an appropriate proxy company. We do not believe that an additional proxy

⁸² Atmos Energy Corporation, Chesapeake Utilities Corporation, New Jersey Resources Corporation, Northwest Natural Holding Company, ONE Gas, Inc., Southwest Gas Holdings, Inc.

⁸³ Document No. 10367-2024, FPUC's Responses to Staff's 19th Data Request, No. 17.

⁸⁴ *Id.*

⁸⁵ *Id.*

⁸⁶ *Id.*

⁸⁷ John Wiley & Sons, Inc., Ingredion, Kinross Gold Corp., HNI Corporation, Kaman Corporation, Smith & Wesson Brands, Inc., Entravision Communications Corporation, Luxfer Holdings, PLC, Natural Grocers by Vitamin Cottage, Inc., Adams Resources & Energy, Inc., Life Vantage Corporation, Sonoco Products, Sensient Technologies.

group beyond the electric and natural gas proxy groups is necessary to estimate the cost of equity for FPUC. Further, based on witness Crowley's quantitative evaluation of his ROE results in Table 2 on page 7 of his testimony, he excluded the results from the Non-Utility Company Proxy Group from the average results used to develop his recommended range of ROEs. In the interest of brevity, we will not critique witness Crowley's cost of equity analysis for his non-utility proxy group and will exclude it from consideration in this case.

6. Cost of Equity Models

Witness Crowley used three cost of equity models applied to his three proxy groups. Those are the constant growth Discounted Cash Flow (DCF) model, the Capital Asset Pricing Model (CAPM) and a Risk Premium (RP) analysis. In addition, witness Crowley included an analysis of the Realized Market Returns for the companies in his electric and gas proxy groups by calculating the historical earned returns based on stock price appreciation and dividends paid for the historical period 2014 through 2023. The assumptions and methodologies used by witness Crowley in his cost of equity models are unorthodox and diverge from traditional methodologies used by other ROE witnesses that have testified before the Commission in prior dockets. Witness Crowley's application of the cost of equity models are not supported by reasonable assumptions for estimating the forward-looking ROE for a regulated utility and the market data used in his models is either stale or not verifiable. Consequently, we will not use witness Crowley's testimony to approve an ROE for FPUC. A summary of witness Crowley's ROE model results as presented in his testimony is provided in Table 18.

TABLE 18
SUMMARY OF FPUC ROE MODEL RESULTS

	Low Results	High Results	Average	Comm. Corrected
Discounted Cash Flow (DCF)				
Mid-Sized Electric Utilities	9.37%	9.77%	9.57%	
Gas Distribution Utilities	9.55%	12.08%	10.81%	
Capital Asset Pricing Model (CAPM)				
Mid-Sized Electric Utilities	10.39%	11.61%	11.18%	
Gas Distribution Utilities	10.14%	11.31%	10.72%	
Low Risk Non-Utility Companies	10.10%	11.63%	11.29%	
Risk Premium Model (RP)				
Mid-Sized Electric Utilities			10.52%	
Gas Distribution Utilities			9.89%	
Low Risk Non-Utility Companies			11.39%	
Realized Market Returns, Rolling 10 Yrs.				
<u>For 2013-2023</u>				
Mid-Sized Electric Utilities			11.52%	9.65%
Gas Distribution Utilities			13.21%	8.95%
Low Risk Non-Utility Companies			9.89%	
FPUC Recommended Return on Equity⁸⁸	10.43%	12.21%	11.30%	
Staff Corrected Range of Results	9.68%	10.90%		10.30%

Sources: Witness Crowley’s Direct Testimony, Table 2, page 7, and staff analysis.

While not described in his testimony, witness Crowley calculated the range of his ROE model results of 10.43 percent to 12.21 percent by deriving the statistical central tendency (not the average) of the low and high DCF model and CAPM results, and Realized Market Returns using a somewhat complex calculation involving the standard deviation of the values in the “Average” column in Table 18 (excluding the Non-Utility Companies).⁸⁹ Witness Crowley

⁸⁸ FPUC’s Recommended ROE range does not equal the average of the values in the Low and High columns due to his method of finding the central tendency using a standard deviation calculation.

⁸⁹ FPUC response to Staff’s 19th Set of Data Requests, No. 14, attached file “DR 19.14 Work Papers”, COE Summary Tab.

apparently did not include the results from his RP analysis in his average final results. His estimated ROEs include an upward adjustment of 14 basis points to recognize flotation costs.

In general terms, witness Crowley “averaged” his low results from the DCF model, the CAPM, and the Realized Market Returns for both the electric and gas proxy groups to derive the low end of his range of results of 10.43 percent as shown in Table 18. He repeated his process using the high results of his models to derive the high end of his range of results of 12.21 percent. When calculating his low and high estimates witness Crowley included the historical Realized Market Returns of 11.52 percent and 13.21 percent for both his electric and gas proxy groups, respectively. The addition of the Realized Market Returns in his low- and high-end averages simply increased witness Crowley’s overall results. Excluding the Realized Market Returns from his calculations yields a range of 10.21 percent to 11.20 percent with a central tendency of 10.72 percent.

Witness Crowley apparently based his recommended ROE of 11.30 percent on the mid-point of his range of results of 10.43 percent to 12.21 percent. The values in the “Average” column (excluding the Non-Utility Companies) were used to calculate the standard deviation of the low and high results from his ROE models to develop the central tendency of his results. That methodology increased the range of his overall results. The values in the “Average” column do not equal 11.30 percent. The average equals 10.93 percent.

Most importantly, witness Crowley apparently made an error in deriving his range of “Average” results as denoted in Table 16 and Table 2, page 7 of his testimony. In Table 2, for his estimate of the 2023 10-year Realized Market Returns, he incorrectly listed 11.52 percent for the electric proxy group and 13.21 percent for the gas proxy group which are from 2022, not 2023. As shown in Exhibits NAC-29 and NAC-31, and in his work papers, the 2023 10-year returns for the electric and gas proxy groups as presented are 9.65 percent and 8.95 percent, respectively. After making those changes to correct witness Crowley’s Table 2 to match the results described therein, and adjusting the same in the calculations in his worksheets, his range of ROE results becomes 9.68 percent to 10.90 percent, averaging 10.30 percent, including flotation costs.

7. FPUC DCF Model

Witness Crowley used the single-stage constant growth DCF methodology to estimate the investor required return of his electric and gas proxy groups. Expressed mathematically as: $ROE = (\text{dividend} \div \text{stock price}) + \text{growth rate}$. Witness Crowley adjusted the dividend yield by increasing the dividend by a factor of $\frac{1}{2}$ the growth rate. The basic equation he used was $ROE = [(\text{dividend} \times 1 + 0.5 \text{ growth rate}) \div \text{stock price}] + \text{growth rate}$. For the stock price, witness Crowley used the closing price on the first trading day of May for each of the companies in his electric and gas proxy groups. The stock prices from May of 2023 are now over 20 months in the past and don’t represent the most recent stock market price data. Witness Crowley’s testimony was filed on August 22, 2024. He could have included market data through at least May of 2024. Witness Crowley’s growth rates for the electric and gas companies in 2023 were the average of estimated growth rates obtained from Zack’s and Yahoo Finance. The low results from witness Crowley’s DCF model application reflect data from 2023 which is more recent than

his high results which reflect data from 2021 and 2022. His low results were 9.37 percent for the electric proxy group and 9.55 percent for the gas proxy group.

Witness Crowley explained that expected growth rates for 2021 and 2022 were not available from Zacks and Yahoo Finance at the time of his analysis and 10-year average historical growth rates for each company were used to calculate earnings per share for 2021 and 2022. The 2021 and 2022 growth rates reflected a weighting of 90 percent of earnings per share plus a 10 percent weighting of the dividends per share. The 10-year average of the earnings per share and dividends per share were calculated using the average of the geometric mean and the arithmetic mean.

Witness Crowley has stated that “[e]lectric and gas utilities generally exhibit stable earnings and dividend growth, and while not perfect predictors of future earnings because of unforeseen economic events, historical growth rates in earnings and dividends serve as a benchmark and are a reasonable estimate of near-term earnings growth.”⁹⁰ Witness Crowley cited Professor Damodaran’s text and paraphrased that one method to estimate the growth of any firm is to look at growth in a firm’s past earnings which can be useful input when valuing stable firms such as the companies in the electric and gas proxy groups. However, Professor Damodaran also stated in his text that “[t]he historical growth rate can often not be estimated, and even if it can, it cannot be relied upon as an estimate of expected future growth.” He also stated that “[e]stimating growth rates can also be complicated by the presence of negative earnings in the past or in the current period.”

In fact, some of the companies in the electric and gas proxy groups had negative earnings for some of the historical years as presented in witness Crowley’s work papers. Professor Damodaran also wrote that using approaches – such as the method used by witness Crowley – to estimate historical growth rates do not provide any information on whether the growth rates are useful in predicting future growth. Professor Damodaran wrote that “[i]t is not incorrect and, in fact it may be appropriate, to conclude that the historical growth rate is ‘not meaningful’ when earnings are negative and to ignore it in predicting future growth.”⁹¹ Therefore, we conclude that it is unreasonable to use historical growth rates to predict expected growth rates in the DCF model for estimating the required ROE for regulated utilities. Witness Crowley also admitted that for some companies, the historical growth rate of earnings or dividends was clearly not reflective of forward-looking growth, as the historical data was anomalous. In those instances, he used the average growth rates from the remaining companies. In addition, the historical returns from 2021 and 2022 using the DCF model results do not reflect current market data and we therefore will not consider them.

In his 2023 DCF model analysis, witness Crowley used the same growth rate of 6.04 percent for two of his electric proxy companies.⁹² As explained by witness Crowley, the growth rate estimates for Northwestern Energy Group were not believable, and earnings growth estimates for Unitil Corporation were not available. Again, witness Crowley used the average

⁹⁰ Document No. 00338-2025, p. 3.

⁹¹ *Security Analysis for Investment and Corporate Finance*, Chapter 11, Aswath Damodaran.

⁹² Northwestern Energy Corp, and Unitil Corporation.

growth rates from the remaining companies in his proxy group and not the actual growth rates of the individual companies. If the information was not available or believable, the companies should have been excluded from the proxy group. Witness Crowley was unable to provide copies of his source information as support for the stock prices, dividends, and growth rates used in his DCF analysis, and consequently, we were unable to verify the information. Based on these flaws in his calculations and the unsupported data, we find that witness Crowley's DCF analysis is unreliable and doesn't reflect current investor expectations or the prospective required rate of return for the proxy groups or FPUC.

8. Staff DCF Model Results

Our staff applied a DCF model to the same electric and gas proxy groups as witness Crowley excluding Otter Tail Corporation, Hawaiian Electric, and Unitil Corporation from the electric proxy group, and Southwest Gas Holdings, Inc. from the gas proxy group. Hawaiian Electric and Unitil Corporation companies were excluded because they do not have forecasted dividends and earnings from Value Line. Otter Tail Corporation and Southwest Gas Holdings, Inc. were excluded because the companies obtain less than 50 percent of revenues from regulated operations. We used the same single-stage constant growth DCF model as did witness Crowley: $ROE = [(dividend \times 1 + 0.5 \text{ growth rate}) \div \text{stock price}] + \text{growth rate}$. First we calculated the dividend yield ($dividend \div \text{stock price}$) for each company in the proxy group. We relied on the company reports as published by Value Line for the dividend and Yahoo Finance for the average stock price in December 2024. We adjusted the dividend by multiplying the dividend paid in 2024 by one-half the forecasted growth rate. The average adjusted dividend yields for the electric and gas proxy groups were 3.75 percent and 3.31 percent, respectively. We relied on the forecasted annual rates of change of earnings per share as estimated by Value Line for the growth rate. The average growth rates for the electric and gas proxy groups were 5.75 percent and 5.70 percent, respectively. We weighted the results by the market capitalization as reported by Value Lines of each company in the proxy groups. The weighted average of our single-stage constant growth DCF results were 9.62 percent and 9.00 percent, for the electric and gas proxy groups, respectively.

9. CAPM

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). 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. 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: $ROE = \text{risk-free rate} + \text{Beta} (\text{market return} - \text{risk-free rate})$. Witness Crowley used the same expected stock market returns and risk-free rates in his CAPM for both the electric and gas proxy groups. The only difference between the results from the electric proxy group and the gas proxy group was based on the beta value applied to the MRP.

10. Risk-Free Rate

Witness Crowley testified that he used the risk-free rate equal to the average monthly yield on 30-year U.S. Treasury securities for two timeframes including 2013-2023 and 2021-2023, observed in monthly frequency. However, his work papers show that he calculated a historical risk-free rate of 3.39 percent from the period January 1, 2018 through June 1, 2024, excluding the period during Covid-19 (March 1, 2020 through June 1, 2021). The other risk-free rate of 4.31 percent was calculated using the time period April 1, 2023 through June 1, 2024. The CAPM is a forward-looking model for which the inputs should reflect forecasted and expected data. Blue Chip Financial Forecasts provides forecasted 30-year U.S. Treasury rates for the future five quarters from the issue date. The most recent Blue Chip forecast for the 30-year U.S. Treasury Yield in 2025 is 4.66 percent.⁹³ Hence, the more appropriate risk-free rate for witness Crowley's CAPM analysis is his estimate of 4.31 percent because it is closer to the forecasted rate of 4.66 percent.

11. Expected Market Return

Witness Crowley's expected stock market return was based on historical realized returns for U.S. markets, measured in real terms. Once estimated, the observed real rate of return for equity markets was adjusted upwards for expected inflation of 2.46 percent. The inflation estimate of 2.46 percent was calculated using the average estimated Treasury Inflation Protected Securities (TIPS) that compares 5-year to 10-year inflation expectations, and the average of three surveys.⁹⁴ Real rates of return were calculated as the arithmetic average of annual U.S. stock market returns over two timeframes, 1970 through 2023, and 1990 through 2023. These results are then adjusted to account for current expected inflation.

Witness Crowley's low end expected market return of 10.63 percent is derived using historical returns from the total U.S. Markets during the period 1970 through 2023. His high end expected market return of 11.62 percent is derived from total U.S. Markets during the period 1990 through 2023. He averaged the two estimates to arrive at an expected market return of 11.13 percent. We have concerns regarding the use of these ex-post methods. A realized return is the holding-period return earned in the past, whereas the expected return is the holding-period return for a stock in the future based on expected dividend yield and the expected price appreciation return. Realized returns can be substantially different from expected returns due to changes in economic conditions and business cycle interruptions and don't necessarily reflect expected returns. For estimating the required ROE for rate setting purposes, we find that realized or historical returns are not a reliable indicator of expected returns. As such, witness Crowley's ex post method to estimate the expected market return is questionable and we will not rely upon it.

⁹³ *Blue Chip Financial Forecasts*, Vol. 44, No. 2, January 31, 2025.

⁹⁴ Document No. 10367-2024, p 15-16. The average of three surveys for the years 2024 and 2025: the Livingston Survey conducted by the Federal Reserve Bank of Philadelphia, the Survey of Consumer Expectations by the University of Michigan, and the Survey of Professional Forecasters also conducted by the Federal Reserve Bank of Philadelphia.

12. Beta Value

Witness Crowley obtained his 2023 betas for the electric and gas proxy groups from Morningstar and Yahoo Finance. Again, staff was unable to confirm the beta values because the source information was not provided. Witness Crowley adjusted the raw betas to account for central tendency by applying the Blume method to the beta values. This adjustment resulted in moving the raw betas for both the gas companies and electric companies closer to 1.0. The effect of this adjustment was to produce CAPM results close to or at the expected market return which indicates that his proxy groups are not much more or less risky than the market as a whole. The weighted average adjusted beta values witness Crowley used to calculate his CAPM results for the electric and gas proxy groups were 1.01 and 0.944, respectively. In comparison, the weighted average of the betas published in Value Line for the electric and gas proxy groups are slightly lower at 0.983 and 0.907, respectively. The lower beta values would produce a lower ROE result indicating that applying the Blume adjustment increases the results of the CAPM.

13. FPUC CAPM Results

For the electric proxy group, witness Crowley's low CAPM estimate was 10.39 percent, and his high CAPM estimate was 11.61 percent. The weighted average result was 11.18 percent. The simple average of the low and high CAPM results was 11.00 percent. For the gas proxy group, the low end CAPM estimate was 10.14 percent and the high end CAPM estimate was 11.31 percent. The weighted average results were 10.72 percent. The simple average was also 10.72 percent. We will not rely on witness Crowley's CAPM estimates because they include MRP estimates based on ex post methodologies, do not reflect forecasted risk-free interest rates, and use adjusted betas that skew his results upwards.

14. Staff CAPM Results

As a comparison, we applied a CAPM to the same electric and gas proxy group as witness Crowley excluding Otter Tail Corporation, Hawaiian Electric, and Unitol Corporation from the electric proxy group, and Southwest Gas Holdings, Inc. from the gas proxy group. We used the same CAPM methodology approved by us in our annual leverage formula.⁹⁵ We relied on an estimated market return for companies followed by Value Line, the average projected yield on the U.S. Treasury's 30-year bonds for the five quarters from the second quarter of 2025 through the second quarter of 2026, as of January 31, 2025, published by Blue Chip Financial Forecasts (4.66 percent), and the weighted average beta for the electric and gas proxy groups of 0.988 and 0.8973, respectively. An expected return on the overall stock market of 10.81 percent was calculated using a quarterly DCF model applied to a large number of dividend-paying publicly traded companies with stock prices as of January 14, 2025. The average beta of the proxy groups was weighted using the market capitalization of each company as reported by Value Line. Our estimated expected MRP is 6.15 percent ($10.81\% - 4.66\% = 6.15\%$). Our CAPM results were 10.74 percent and 10.18 percent for the electric and gas proxy groups, respectively.

⁹⁵ 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)(j), F.S.*

15. FPUC Risk Premium Analysis

A risk premium method estimates the required return on equity in excess of the return one could receive for an investment in risk-free assets. In this case, witness Crowley derived an equity MRP based on the historical return on the total U.S. stock market from 2014 to 2023, less the return on long-term U.S. Treasury Bonds over the same time period. He then multiplied the average betas of the electric and gas proxy groups to calculate a beta adjusted MRP. He then added a risk-free rate to the beta adjusted MRP to calculate his RP estimated ROE. By applying the beta values of the proxy groups to the MRP and adding the risk-free rate to the product, the end result is another CAPM application.

To derive his RP result, witness Crowley first estimated the expected inflation at 3.98 percent. The 3.98 percent inflation estimate added 1.53 percent to witness Crowley's inflation estimate of 2.46 percent from his CAPM expected market return calculation. The additional 1.53 percent is the Laubach-Williams R-star estimate that reflects short-term inflation.⁹⁶ He then added the differential of real returns on intermediate and long-term U.S. Treasury Bonds to estimate a risk-free rate of 5.43 percent. For his risk premium, he calculated the difference between the 10-year average from 2014 to 2023 of equity returns and real returns on long-term U.S. Treasury Bonds and obtained a result of 5.83 percent. He then multiplied the risk premium by the unadjusted beta values of the electric (0.873) and gas (0.764) proxy groups to calculate the market risk premium for proxy groups. He added the risk-free rate of 5.43 percent to each proxy group risk premium to derive his final RP estimate.

His results for the electric and gas proxy groups were 10.52 percent and 9.89 percent, respectively. It is important to note that all of the data inputs used by witness Crowley were historical and reflected data more than a year in the past, and consequently, do not indicate a forward-looking required return. Further, as mentioned previously, witness Crowley did not use the results from his RP analysis in his final derivation of his range of results although he did appear to use it to calculate the standard deviation applied to his other results to determine the central tendency. Therefore, we conclude that we will not consider witness Crowley's results from his RP analysis in our decision.

16. FPUC Realized Returns Analysis

Witness Crowley used the 10-year average realized market returns from the proxy companies over the past three years (2021, 2022, and 2023) to estimate investors required return in the future. We find that the realized returns from 2021 and 2022 are dated and shall not be considered. While the 2023 results reflect more recent market information, they do not indicate a ROE of 11.30 percent. The method witness Crowley used is also referred to as a comparable earnings approach, which typically uses realized book returns from companies with similar risk characteristics as a comparison to the regulated subject company. The basic premise of the comparable earnings approach is that regulation should emulate the competitive result.

⁹⁶ The Laubach-Williams model provides estimates of the natural rate of interest, or r-star, and related variables. This approach defines r-star as the real short-term interest rate expected to prevail when an economy is at full strength and inflation is stable.

However, there are several issues with this method. First, using companies that have substantial regulated revenues can be circular. That is, returns earned on past investments reflect past regulatory awarded ROEs and don't reflect the opportunity cost of investing in non-regulated companies with similar risk. Second, the comparable earnings approach uses historic earned returns to indicate the cost of equity, whereas in a regulatory proceeding prospective required returns need to be considered. Third, the actual cost of equity for a regulated utility is most appropriately determined by the application of the CAPM and DCF Model. In this case witness Crowley calculated the annual change in stock price, plus dividends paid for each company in the electric and gas proxy groups, and a non-regulated, non-utility group of companies. This method simply calculates what investors have received in the past and does not take into account any forward-looking estimates of ROE or earnings that are available from Value Line and other sources. The results witness Crowley obtained for the 10-year average ending in 2023 for the electric and gas proxy groups were 9.65 percent and 8.95 percent, respectively. The results obtained from the 5-year average 2019 through 2023 for the non-utility proxy group was 9.89 percent. For these reasons, witness Crowley's realized market return analysis is not reasonable nor do his most recent results from 2023 support a ROE of 11.30 percent.

17. 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. Conversely, a company with a comparatively higher equity ratio will have less financial risk, all else equal, and the required return will be lower than a comparable company with a lower equity ratio.

Witness Crowley did not address financial risk in his testimony. We obtained the 2025 forecasted equity ratios for each of the companies in the electric and gas proxy groups as provided in Value Line Reports. The weighted average projected 2025 equity ratios for the electric and gas proxy groups, excluding Otter Tail Corporation, Hawaiian Electric, and Unitil Corporation from the electric proxy group, and Southwest Gas Holdings, Inc. from the gas proxy group, were 45.15 percent and 55.21 percent, respectively. The weighted average equity ratio of the combined electric and gas proxy groups is 48.00 percent. FPUC's equity ratio for the 2025 projected test year is 50.04 percent. Additionally, the average Standard & Poor's (S&P) credit rating for the combined electric and gas proxy groups is BBB+ which is one notch higher than that of CUC at an S&P equivalent credit rating of BBB, indicating FPUC's credit metrics are comparable to the proxy groups.⁹⁷ Therefore, we find that the proxy groups, on average, have similar financial risk to that of CUC and FPUC.

⁹⁷ FPUC witness Russel testified that Chesapeake Utilities Corporation has a credit rating of NAIC-2B which is equivalent to an S&P credit rating of BBB, p. 5.

18. Flotation Costs

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. Therefore, in order for the ROE to reflect the full cost of equity realized by a company, flotation costs shall be accounted for in the estimated cost of equity.

We have a long-standing policy to recognize flotation costs in the cost of equity models used to estimate the ROE. Witness Crowley made an upward flotation cost adjustment to his ROE model results of approximately 14 basis points based on the stock issuance costs of CUC. We have approved a similar methodology to derive the flotation costs in prior litigated rate cases.⁹⁸ Therefore, we find that the flotation cost adjustment of 14 basis points is reasonable. Our DCF model includes a flotation cost in the result by making a reduction to the stock price of 3 percent. The result of this adjustment increased the result of the DCF model by 14 basis points. Therefore, we find that a 14-basis point adjustment for flotation costs is reasonable.

19. Business Risk

Witness Crowley did not provide an analysis of the business and operational risks of FPUC as compared to the companies in his electric proxy group. We find that FPUC's business and operational risks are lower than the electric companies in the proxy group. FPUC provides only transmission and distribution electric service and does not own or operate any electric generation assets. Witness Crowley's electric proxy group includes vertically integrated electric companies, that is, the companies own and operate electric generation assets in addition to providing transmission and distribution service. Vertically integrated electric companies are riskier than distribution-only electric companies and typically receive higher authorized returns on equity for bearing the higher business and operational risk. A report by Regulatory Research Associates (RRA) published on February 5, 2025, found "[t]he annual average authorized ROEs in vertically integrated cases involving generation have historically been about 30-65 basis points higher than in distribution-only cases." RRA also stated the difference likely reflects the increased risk associated with the ownership and operation of generation assets.⁹⁹ In 2024, the industry average authorized ROE for vertically integrated electric utilities was 9.84 percent as compared to 9.53 percent for electric distribution-only cases, a difference of 31 basis points.¹⁰⁰ However, when comparing FPUC's business risks to the companies in the gas proxy group, FPUC's exposure to extreme weather risk is greater than the gas companies. On balance, we find that FPUC's business and operational risks are comparable to the combined electric and gas proxy groups.

⁹⁸ 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.*, and Order No. PSC-2025-0038-FOF-EI, issued February 3, 2025, in Docket No. 20240026-EI, *In re: Petition for rate increase by Tampa Electric Company*.

⁹⁹ Regulatory Research Associates Focus, *Major energy rate case decisions in the US January-December 2024*, issued February 4, 2025.

¹⁰⁰ *Id.*

20. Comparable Authorized ROEs

We have calculated a ROE of 10.15 percent which is within the range of ROEs that we have recently approved for other Florida electric and natural gas companies (9.50% - 11.00%) as summarized in Table 19. The Florida electric companies' authorized ROEs range from 10.30 percent to 10.80 percent. However, all three of the other Florida electric companies are vertically integrated electric companies which makes them riskier as compared to FPUC, which provides only transmission and distribution electric service. Also, there were seven ROE decisions made by other state regulatory agencies in December 2024 for electric and gas utilities. The ROEs awarded ranged from 9.34 percent to 10.50 percent, and averaged 9.81 percent, including our decision of 10.50 percent in the TECO rate case.¹⁰¹ Of note was an awarded ROE of 9.34 percent for Portland General Electric Company and 10.10 percent for Otter Tail Power Company, two of the companies included in witness Crowley's proxy group.

Table 19
Florida Investor-Owned Electric and Natural Gas approved ROEs

Company	Order Number	Issued	ROE
Duke Energy Florida, LLC	PSC-2024-0472-AS-EI	11/12/2024	10.30%
Florida City Gas	PSC-2023-0177-FOF-GU	06/09/2023	9.50%
Florida Power & Light Company	PSC-2022-0358-FOF-EI	10/21/2022	10.80%
FPUC (Natural Gas Division)	PSC-2023-0103-FOF-GU	03/15/2023	10.25%
Peoples Gas System, Inc.	PSC-2023-0388-FOF-GU	12/27/2023	10.15%
Sebring Gas System, Inc.	PSC-2020-0047-PAA-GU	02/03/2020	11.00%
St. Joe Natural Gas Company, Inc.	PSC-2025-0035-PAA-GU	01/30/2025	10.50%
Tampa Electric Company	PSC-2025-0038-FOF-EI	02/03/2025	10.50%
Average			10.375%

Source: Staff Analysis.

21. Summary

Based on a review of witness Crowley's testimony and ROE analysis, we find that FPUC has not supported its requested ROE of 11.30 percent. Witness Crowley's ROE models do not reflect the required equity returns of investors on a forward-looking basis because his results are largely based on historical data prior to and including 2023, and do not reflect current market conditions and data. Also, witness Crowley apparently made an error in his calculation of the

¹⁰¹ Regulatory Research Associates Focus Notes, issued January 13, 2025, p. 24, Order No. PSC-2025-0038-FOF-EI, issued February 3, 2025, in Docket No. 20240026-EI, *In re: Petition for rate increase by Tampa Electric Company*.

range of his average results, and after correction, his range of results decreased to 9.68 percent to 10.90 percent, with an average of 10.30 percent. Further, some of the companies included in witness Crowley’s proxy groups do not meet the selection criteria he defined and do not have the same business risk characteristics of FPUC, that is, they have a lower percentage of regulated revenues from operations. Witness Crowley did not provide testimony regarding a comparison of business or financial risks of his proxy groups to that of FPUC and no adjustments were made to account for any specific business or financial risks of FPUC as compared to the proxy groups. Based on the analysis presented above, we find that witness Crowley’s cost of equity models shall not be relied upon.

To test the reasonableness of witness Crowley’s DCF model and CAPM results, we applied the same form of DCF model and CAPM to the most recent available market data for the companies in witness Crowley’s electric and gas proxy groups, excluding Otter Tail Corporation, Hawaiian Electric, and Unitil Corporation from the electric proxy group, and Southwest Gas Holdings, Inc. from the gas proxy group. Our cost of equity model results ranged from 9.59 percent to 10.74 percent. We then averaged the results of its DCF model and the CAPM for each proxy group, and then used the weighted average of the electric and gas proxy groups based on market capitalization to derive a final weighted average ROE of 10.01 percent. We added a flotation cost adjustment of 14 basis points (the same as witness Crowley) to the final weighted average to arrive at an ROE of 10.15 percent. Our results are presented in Table 20. The purpose of our cost of equity analysis is to demonstrate that using the most recent ex ante financial market data and projected interest rates as opposed to historical financial returns and older market data results in a significantly lower ROE than the 11.30 percent presented by witness Crowley. Therefore, we find that FPUC’s midpoint ROE be set at 10.15 percent. We find that an ROE of 10.15 percent is appropriate because, on average, it reflects the forward-looking required returns on equity of the electric and gas proxy groups, which on the whole, have comparable risks to FPUC, and therefore, meet the *Hope and Bluefield* standards.

Table 20
ROE Analysis

	DCF	CAPM	Average	Weight	Weighted Avg
Electric proxy group	9.62%	10.74%	10.18%	71.61%	7.2895%
Gas Proxy group	9.00%	10.18%	9.59%	28.39%	2.723%
Average					10.01%
Flotation Cost					0.14%
Weighted Average ROE					10.15%

Source: Staff Analysis

For the reasons stated above, we approve a return on common equity of 10.15 percent, with a range of 9.15 to 11.15 percent for use in establishing FPUC’s revenue requirement for the 2025 projected test year.

G. Capital Structure and Weighted Average Cost of Capital

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. On MFR Schedule D-1a (Supplement), FPUC presented its requested 2025 projected test year capital structure based on a 13-month average as of December 31, 2025, consisting of common equity in the amount of \$64,253,557, long-term debt in the amount of \$56,888,413, and short-term debt in the amount of \$7,255,028. The Regulatory Tax Liability is the unamortized balance of the flow-back of excess deferred income taxes that were created from the Tax Cuts and Jobs Act of 2017.¹⁰² FPUC’s requested jurisdictional capital structure is summarized in Table 21.

Table 21
FPUC Requested 13-Month Average Capital Structure

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$64,253,557	42.82%	11.30%	4.84%
Long-Term Debt	56,888,413	37.91%	4.51%	1.71%
Short-Term Debt	7,255,028	4.83%	5.81%	0.28%
Customer Deposits	4,001,097	2.67%	2.20%	0.06%
Accumulated Deferred Income Taxes	13,206,708	8.80%	0.00%	0.00%
Regulatory Tax Liability	<u>4,448,275</u>	2.96%	0.00%	0.00%
Total	<u>\$150,053,078</u>	100.00%		6.89%

Source: MFR Schedule D-1a (Supplement).

The cost rates and amounts of the capital components are approved in Section V of this order. The 13-month average amounts are taken directly from FPUC’s MFR Schedule D-1a (Supplement). As discussed above, we have made an adjustment to increase the amount of accumulated deferred income taxes (ADITs) by \$310,407. We have also approved a cost rate for customer deposits of 2.20 percent, a cost rate for short-term debt of 5.81 percent, a cost rate for long-term debt of 4.51 percent, and a return on common equity of 10.15 percent. With these adjustments and after reconciling the capital structure to the amount of approved rate base, we approve a WACC of 6.34 percent, which is summarized in Table 22 below.

¹⁰² Order No. PSC-2018-0104-PCO-PU, issued February 26, 2018, in Docket No. 20180013-PU, *In re: Petition to establish generic docket to investigate and adjust rates for 2018 tax savings, by Office of Public Counsel*, and Order No. PSC-2017-0488-PAA-EI, issued December 26, 2017, *In re: Petition for limited proceeding to include reliability and modernization projects in rate base, by Florida Public Utilities Company*.

Table 22
Approved 13-Month Average Capital Structure

Capital Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	\$61,154,478	42.42%	10.15%	4.31%
Long-Term Debt	54,144,567	37.56%	4.51%	1.69%
Short-Term Debt	6,905,103	4.79%	5.81%	0.28%
Customer Deposits	4,001,097	2.78%	2.20%	0.06%
Accumulated Deferred Income Taxes	13,517,115	9.38%	0.00%	0.00%
Regulatory Tax Liability	<u>4,448,275</u>	3.07%	0.00%	0.00%
Total	<u>\$144,170,635</u>	100.00%		6.34%

Sources: Staff Analysis and MFR Schedule D-1a (Supplement).

The net effect of our adjustments is a decrease in the WACC from 6.89 percent as requested by the Company to 6.34 percent. Based upon the proper components, amounts, and cost rates associated with the capital structure for the test year ending December 31, 2025, the projected test year jurisdictional capital structure to be used for establishing FPUC's 2025 projected test year revenue requirement is 42.42 percent common equity, 37.56 percent long-term debt, 4.79 percent short-term debt, 2.78 percent customer deposits, 9.38 percent ADITs, and 3.09 percent regulatory tax liability.

VI. Revenue

A. Miscellaneous Service Revenue

This section addresses what amount of Miscellaneous Service Revenue should be approved for the 2025 projected test year, based on the estimated number of transactions for various service types multiplied by the current charges for each type of service transaction. MFR Schedule C-5, sponsored by FPUC witness Galtman, is the primary schedule for recording all operating revenue types and sources, and Miscellaneous Service Charges are listed on this schedule as a line entry for "Other Operating Revenues."

For the 2025 test year, MFR Schedule C-5 reflects that FPUC is projecting a balance of \$163,225 in Miscellaneous Service Revenues. MFR Schedule E-13b identifies the Miscellaneous Service Charges and the number of transactions (sales) that produce the 2025 revenue addressed in this issue. The detail is shown in Table 23 below:

Table 23
Miscellaneous Service Charge - 2025 Test Year Revenue

Description	Estimated Number of Transactions	Current Charge per Transaction (\$)	Test Year Revenue Total (\$)
Initial Establishment of Service	289	61.00	17,629
Re-establish. Service or Change Account	3,619	26.00	94,094
Customer Disconnect then Reconnect	304	65.00	19,760
Reconn. Svc./ Rule Violation (normal hours)	245	52.00	12,740
Reconn. Svc./ Rule Violation (other hours)	6	178.00	1,068
Collection Charge	1,973	16.00	31,568
Temporary Service	0	85.00	0
Return Check Charge	1,179	43.64	51,454
Miscellaneous Allowances & Adjustments	(1,437)	16.00	<u>(65,088)</u>
2025 Miscellaneous Service Charges (Total)			<u>\$163,225</u>

Source: MFR Schedule E-13b (Revenues by Rate Schedule – Service Charges [Account 451]).

The historic amounts of Miscellaneous Service Revenue amounts that have been recorded since 2020, is reflected in Table 24 below.

Table 24
Revenue from Miscellaneous Service Charge – (2020 – 2025)

Year	Amount (\$)
2020	197,569
2021	198,626
2022	189,246
2023	203,299
2024 (projected)	176,299
2025 (projected)	163,225

Source: FPUC’s Response to staff’s 13th Data Request, Item 5 (Document No. 09977-2024).

The decline in Miscellaneous Service Revenue amounts for the 2024 and 2025 projected test years appear to be driven primarily by fewer 2024 and 2025 transactions projected for the service charges identified as: (1) Initial Establishment of Service and (2) Re-establishing Service

or Change Account. We find that the amount of \$163,225 in Miscellaneous Service Revenue is reasonable and is approved for the 2025 projected test year.

B. Total Operating Revenue

Our previous findings on forecasts of customers, energy and demand by revenue and rate class, estimated revenues from sales of electricity at present rates for the 2025, and Miscellaneous Service Revenue for the 2025 test year provide direct inputs into our decision on this issue. Per our previous decisions, there are no adjustments to FPUC's forecasts of customers, energy sales, demand, or revenue from the sales of electricity at present rates for the 2025 projected test year. The test year revenue from these electricity sales sources is \$24,353,946.

In addition to “Total Revenue From the Sales of Electricity at Present Rates,” FPUC also receives “Other Operating Revenue,” which includes revenue from multiple sources, such as forfeited discounts, miscellaneous service revenues, rent from electric property, etc., which together total \$978,357. We are not making adjustments to any of these revenue amounts as proposed by FPUC.

Summing “Other Operating Revenue” with “Total Revenue From the Sales of Electricity at Present Rates” yields Total Operating Revenue” for the 2025 test year of \$25,353,946, as detailed in Table 25 below.

Table 25
FPUC Operating Revenue Projections – 2025 Test Year

Account Nos.	Account Title	Revenues
440-447	Total Revenue From Sales of Electricity at Present Rates (Section II.D.)	\$24,375,589
450	Forfeited Discounts	\$507,014
451	Miscellaneous Service Revenues	\$163,225
454	Rent From Electric Property	\$269,439
456.2	Other Revenues	\$38,679
	Total Other Operating Revenue	\$978,357
	Total Operating Revenues	\$25,353,946.

Source: MFR Schedule C-5, Page 3 of 3.

Based on the above, we find that the appropriate amount of Total Operating Revenue for the 2025 projected test year is \$25,353,946.

VII. O&M Expenses

A. S&P Global Platts Package

The S&P Global Platts Commodity Service Model is a premium subscription platform used for forecasting commodity prices. For FPUC, natural gas prices must be forecasted in order to complete its fuel cost projection petition filed in the annual Fuel and Purchased Power Cost Recovery Clause and to assess potential costs associated with its purchased power agreements in general.¹⁰³ The total cost for the 2025 S&P Global Platts subscription is \$71,136, with \$26,887 being allocated to FPUC's electric division.

B. Fuel Revenue and Fuel Expenses

Fuel revenues and fuel expenses are processed through the Fuel and Purchased Power Cost Recovery Clause and the corresponding fuel cost recovery charge. As such, fuel revenues and expenses should not be included in the derivation of base rates. Thus, the purpose of this section is to ensure any fuel revenues and expenses that are recovered in the Fuel and Purchased Power Cost Recovery Clause have been removed from the calculation of base rates.

As detailed in MFR Schedule C-2 (2025), FPUC removed \$65,063,104 of revenue associated with projected cost requirements and recoveries in the Fuel and Purchased Power Cost Recovery Clause. For fuel-related purchased power costs, FPUC removed a total expense of \$52,194,761 including taxes. The balance of the revenue adjustment, or \$12,875,012, is revenue associated with demand costs that are also recovered in the Fuel and Purchased Power Cost Recovery Clause.

Upon review we find that FPUC has made the appropriate test year adjustments to remove fuel revenues and fuel expenses recoverable through the Fuel and Purchased Power Cost Recovery Clause.

C. Conservation Revenue and Expenses

For the projected 2025 test year, FPUC removed \$883,887 in conservation revenues and an equal amount in conservation expenses recoverable through the Conservation Cost Recovery Clause. These amounts are removed adjustments to Net Operating Income in MFR Schedule C-2, and are removed as negative income and expense adjustment entries to signify that these are amounts that reduce the total revenues and total expenses of the Company. Similar amounts and adjustments were made for the projected 2024 test year (\$883,573), and for the 2023 historic test year as well (\$700,392). The process is explained in the direct testimony of FPUC witness Napier.¹⁰⁴ She states:

Consistent with prior rate proceedings, the fuel and conservation revenues and expenses, as well as their respective net under recoveries, have been eliminated from both the historic and projected test years. The items are handled in separate dockets outside of the base rate proceeding and are appropriate for review and approval within those separate proceedings.

¹⁰³ FPUC Responses to Staff's Fourth Data Request, Document No. 09690-2024.

¹⁰⁴ Direct Testimony of Michelle Napier, Page 15, Lines 18-22, Document No. 08583-2024.

The referenced amounts are shown on MFR Schedule C-2 as negative adjustment entries, which indicates the amounts are adjustments that reduce the total revenues and total expenses of the Company. We find such adjustments are appropriate because the referenced revenue and expense amounts are subject to recovery through the Energy Conservation Cost Recovery clause mechanism, rather than through base rate recovery.

D. Electric Line Operation Supervisors

In its 2025 projected test year, FPUC has included the costs associated with the addition of a new Electric Line Operation Supervisor in both its Northeast and Northwest territories for a total of two new positions. FPUC indicated that these positions were added in order to remain in compliance with its O&M policies. To facilitate this, these positions would be responsible for overseeing distribution line crews, monitoring material used/spent, facilitating training, reviewing qualifications, ensuring safety equipment compliance, monitoring fleet compliance and performance, ensuring compliance with construction standards, performing field safety observations, overseeing time coding, and performance reviews. These positions were filled in October 2024, with a salary of \$105,000 for each position.

FPUC previously leveraged the Manager of Electric Operations, Engineering and Safety, as well as contractors, to address the Electric Line Operation Supervisors' responsibilities. However, due to increased workload and complexity of the work, FPUC stated in response to staff data requests that it was necessary to add the supervisor positions to provide direct oversight of distribution line workers, and ensure the safest and most efficient work environment.¹⁰⁵ These positions will provide an additional level of supervision necessary to assist construction personnel while also consolidating the responsibilities outlined above into a single source. Additionally, FPUC indicated that these positions would allow management personnel to focus more on strategic activities while the supervisors support field crews.

We have reviewed these positions and believes that they will provide FPUC with the supervision necessary to remain in compliance with its O&M policies by overseeing the performance and safety of field employees and contractors, amongst other responsibilities. As such, we approve FPUC's proposed addition of an Electric Line Operation Supervisor in both its Northeast and Northwest territories for inclusion in the 2025 projected test year with no adjustments.

E. Storm Hardening

In 2023, 2024, and 2025, FPUC made adjustments to move Storm Protection Plan (SPP) revenue and under-recovery from base rates to the Storm Protection Plan Cost Recovery Clause (SPPCRC). In 2023, 2024, and 2025, FPUC also made adjustments to remove SPP-related income and other taxes, as well as depreciation expenses. Furthermore, FPUC reallocated tree trimming and inspection costs, and associated income tax from base rates to the 2025 SPPCRC.

In MFR Schedule C-7, FPUC made adjustments using inflation and customer growth rates, further adjusting for tree trimming and inspection costs. These total amounts were then removed from MFR Schedule C-2 for 2024 and 2025, respectively. In its Fifteenth Data

¹⁰⁵ Response No. 27 in Staff's Sixth Data Request, Document No. 09794-2024.

Request, we asked whether FPUC had made the appropriate adjustments to remove all storm hardening revenues and expenses recoverable through the SPPCRC for the 2025 projected test year. FPUC stated that it had inadvertently removed the 2024 inspection cost from its 2025 MFRs causing \$57,238 in net over recovery of expenses.

FPUC's C-2 and C-3 MFRs show a decrease in Net Operating Income (NOI) of \$1,169,117 in 2025 for the SPPCRC, which includes \$5,494,310 in total operating revenues minus \$4,325,193 in total operating expenses. FPUC removed an NOI of \$721,522 in 2024, which includes \$3,133,444 in total operating revenues minus \$2,411,922 in total operating expenses. FPUC removed an NOI of \$524,274 in 2023, which includes \$1,325,715 in total operating revenues minus \$801,441 in total operating expenses.

According to our staff's audit, FPUC made an adjustment of (\$413,690) to working capital to remove under-recovery which was interest earning, for its SPP. In addition, the amount of (\$413,690) was included in the Fuel Under-Recovery adjustment. Our audit staff determined that the amount of (\$413,690) was removed twice. However, the adjustment has no effect on the projected 2025 test year.

Pursuant to 366.96, F.S. and Rule 25-6.031, F.A.C., utilities may recover costs for SPP activities through base rates or the SPPCRC. We find that FPUC's adjustments are reasonable. Therefore, we find that FPUC has made the appropriate SPPCRC adjustments, as shown on MFR schedules C-2, C-3, C-7, and in the above-mentioned discovery.

F. Reserve Target Level and Storm Damage Accrual

FPUC witness Napier explained that the Company is requesting an increase in its annual storm reserve accrual due to exposure to the risk of storm damage, the conditions relating to storm activity changing in Florida, and a current projection for the storm reserve to be underfunded by the end of the 2025 test year. Storm costs in 2024 are estimated to be \$778,816, and FPUC projects storm costs for 2025 to be \$619,454, which would create a deficit of \$734,893 in FPUC's storm reserve by the end of the 2025 test year. The 2025 projected storm costs are an average of FPUC's actual storm costs for 2020 through 2023 plus the estimates of the 2024 costs. Additionally, FPUC requested to spread the collection of its reserve replenishment over five years in order to mitigate the rate impact to its customers. The resulting calculation amounts to \$446,979 annually.

Rule 25-6.0143, F.A.C., addresses the establishment of a storm reserve account and outlines the types of storm related costs that an investor-owned electric utility can charge to its storm reserve. FPUC's existing storm reserve target level is \$1.5 million and its existing annual storm damage accrual is \$121,620.¹⁰⁶ If FPUC's annual storm damage accrual remains unchanged, it would take 18 years to replenish the storm reserve target level to \$1.5 million. FPUC is requesting to increase its annual accrual amount by approximately \$325,359 to \$446,979, in order to collect \$2,234,894 over five years. This will replenish the level of the

¹⁰⁶ Order No. PSC-08-0327-FOF-EI, issued May 19, 2008, in Docket No. 070304-EI, *In re: Petition for rate increase by Florida Public Utilities Company* and Order No. PSC-2019-0114-FOF-EI, issued March 26, 2019, in Docket No. 20180061-EI, *In re: Petition for limited proceeding to recover incremental storm restoration costs, by Florida Public Utilities Company*.

storm reserve to \$1.5 million. The Company did not request any changes to its existing reserve target level of \$1.5 million.

We agree with FPUC's calculations which demonstrate that its storm reserve would be deficient by the end of 2025 if its annual accrual remains unchanged. Additionally, we recognize the need for FPUC to maintain its storm reserve given the Company's risk of storm damage. FPUC's proposed increase to its annual accrual is reasonable. Therefore, we find that FPUC's proposed reserve target level of \$1.5 million and annual storm damage accrual of \$446,979 for the 2025 projected test year are appropriate and are hereby approved.

G. Advertising Expense

Advertising serves to convey information regarding utility services, safety, conservation, and other customer-related matters. FPUC has estimated an advertising expense of \$103,998 for the 2025 projected test year, reflecting an increase of \$2,662 from the previous year's expense of \$101,336. The Company indicated it anticipates its 2025 advertisement expense will remain consistent with those of recent years.¹⁰⁷ Thus, FPUC's 2024 advertising budget was only increased by the customer growth and inflation factor of 1.0263 to arrive at the 2025 budgeted amount.

Based on the above, we approve an advertising expense of \$103,998 for the 2025 projected test year.

H. Economic Development Expense

As defined by Rule 25-6.0426, F.A.C., economic development refers to activities aimed at enhancing the quality of life for all Floridians by supporting businesses or creating jobs. FPUC is permitted to recover most expenses associated with these activities. In compliance with Rule 25-6.0426(3)(b), F.A.C., the Company reduced economic development expenses by five percent of the total cost. This adjustment remains below the allowable maximum total of 0.225 percent of gross revenues for the 2025 projected test year.

In MFR C-3, FPUC removed a pretax total of \$953 for its portion of the 2025 test year economic development expense.¹⁰⁸ This adjustment was calculated by multiplying the total expense of \$18,000 by 5 percent and then applying an inflation/customer growth factor of 1.0586 (from 2023 to 2025). FPUC has confirmed that all economic development expenditures will conform to the guidelines set forth in Rule 25-6.0426(3)(b), F.A.C.¹⁰⁹ We have reviewed the Company's request and find that it complies with the applicable rule.

For the reasons stated above, we approve an economic development expense of \$19,055 for the 2025 projected test year.

¹⁰⁷ FPUC Responses to Staff's First Data Request, Document No. 09266-2024.

¹⁰⁸ Document No. 08594-2024.

¹⁰⁹ FPUC Responses to Staff's Twenty Second Data Request, Document No. 00016-2025.

I. Rate Case Expense

Generally, rate case costs encompass preparing and effectuating a rate case. On MFR Schedule C-10, FPUC projected a total rate case cost of \$1,530,907. This cost is proposed to be recovered over a four-year amortization period, which yields a test year amortization expense of \$382,727.¹¹⁰ FPUC witness Napier stated that the Company is not staffed at a level to process a rate case proceeding, and instead, hires extra assistance when needed. This includes legal services, contracting with expert witnesses and consultants, and hiring a full-time temporary internal staff to assist with processing the rate case work. The components of FPUC’s requested rate case cost is summarized in Table 26.

OPC has argued that FPUC’s rate case expense should be amortized over a five year, not four year period.¹¹¹ We agree. Amortization over a five-year period yields a test year amortization expense of \$306,182.

Table 26
Rate Case Cost

Description	Cost
Legal Services	\$133,500
Outside Consultants	596,105
Additional/Temporary Resources above Baseline	772,497
Travel	<u>28,805</u>
Total	<u>\$1,530,907</u>

Source: MRF Schedule C-10.

Therefore, we approve a rate case cost of \$1,530,907, amortized over five years, which results in a test year amortization expense of \$306,182.

J. Cost Allocation Methodologies

Affiliate Administrative and General Expenses (A&G) are either directly recorded to FPUC or allocated from groups performing shared services across business units. These A&G expenses encompass employee salaries and benefits, office supplies, and third-party administrative services, e.g., legal services, human resource consulting, financial statement audits, insurance, advertising, and the facilities costs associated with office locations. Additionally, A&G expense includes pension and benefit costs specific to the Company.

The Company states that allocations of A&G expenses are reviewed annually, or as significant changes occur, to ensure they are distributed appropriately among business units.¹¹² CUC’s Cost Accounting Manual (CAM) outlines the allocation practices and methodologies used to account for all allocated Operations and Maintenance expenses, including A&G costs.

¹¹⁰ Document No. 08594-2024.

¹¹¹ Document No. 01169-2025.

¹¹² Direct Testimony of Michael Galtman, Document No. 08584-2024.

The CAM's purpose is to document these allocation practices and methodologies as they are applied through the Company's accounting processes and financial reporting systems. Further, the CAM is meant to ensure that CUC's financial practices and methodologies prevent the subsidization of non-regulated business activities by its regulated electric operations.

FPUC's instant request contains several methodologies of cost allocation. The allocation methodologies are designed to reflect the size and benefit of each business unit. These allocations may be based on metrics such as payroll, profitability, adjusted gross plant, adjusted capital expenditures, or the specific level of effort or focus. A&G expenses are further divided among departments to facilitate precise tracking and recording.

FPUC and/or CUC employ three primary allocation methodologies:

1. **Modified Distringas Formula:** This methodology - based on a Federal Energy Regulatory Commission-approved formula - uses three equally weighted factors: gross plant, earnings before income taxes, and labor cost (payroll) to determine allocation amounts. Departments utilizing this method include Accounting and Finance, Information and Technology (IT) Network, Data and Desktop Maintenance and Support, Human Resources, Internal Audit, Security, Safety, Facilities, and Communications.
2. **Task-Based Allocation:** This methodology considers the department's functions and assigns functions at different levels based on effort or focus to each business unit receiving its services. CUC utilizes this method to allocate costs associated with the Audit Committee, projects within IT departments, management, leadership, treasury, accounts payable, Regulatory Affairs, and specific IT systems.
3. **Capital Expenditure-Based Allocation:** This methodology allocates costs based on capital expenditures in each business unit. This includes costs associated with corporate governance, the CUC Board of Directors, and investor relations. These associations are related to growth which are driven by capital expenditures.

FPUC provided the CAM applicable to CUC companies/affiliates.¹¹³ The CAM provides detailed documentation of the cost allocation methodologies present in this proceeding. Following our review, we find that CUC's CAM aligns with our "Cost Allocation and Affiliate Transactions" rule, or Rule 25-6.1351, F.A.C. In general, this rule establishes guidelines for allocating costs among affiliates to prevent cross-subsidization and ensure transparency. We find that the CAM, and the cost allocation methodologies contained therein, are reasonable and adequately support FPUC's request. Therefore, no adjustments are necessary.

K. Salaries and Benefits

FPUC witness Devon stated that the Company's salary and benefit expenses are reasonable and necessary. Witness Devon explained that FPUC's proposed compensation

¹¹³ FPUC Responses to Staff's First Data Request, Document No. 09266-2024.

package, which includes base pay, long-term, and short-term incentive plans is necessary in order to attract and retain skilled team members in the competitive job environment.¹¹⁴

CUC commissioned a compensation study which FPUC utilized in preparing its rate case.¹¹⁵ In evaluating the compensation study, staff observed that FPUC's base salary is comparable to the market median and competitive with the market overall. We also reviewed FPUC's recent historical and forecasted benefit accounts and asked the Company to explain any items that displayed significant variation (increasing or decreasing significantly year over year).¹¹⁶ Notable benefit accounts with large variations included Retiree Benefits, Other Health Benefits, and Other Benefits. We find that the Company's explanations for these shifts, such as reduced retirement benefits, reductions related to adjusting for prior year's workers compensation exposure, and a new Other Benefits program are reasonable. Based on our analysis, the appropriate level of FPUC's salaries and benefits package for the 2025 projected test year is \$11,388,043.

L. Bad Debt Expense

The purpose of Bad Debt expense is to compensate the Company for uncollectible service charges. On MFR Schedule C-11, FPUC stated its Bad Debt expense for the 2025 projected test year should be \$602,010. This value contributes to an average bad debt rate of 0.5227 percent that was incorporated into the Revenue Expansion Factor, as shown on Schedule C-44.¹¹⁷ The proposed bad debt rate reflects a three-year average of the 2023 historical test year, the 2024 prior year, and the as-filed 2025 projected test year amounts. In addition, the proposed bad debt is lower than the three-year historical average of calendar years 2021, 2022, and 2023, which results in an average bad debt rate of 0.6628 percent. Therefore, we find that the appropriate amount of Bad Debt expense for ratemaking purposes is \$602,010 and the average bad debt rate is 0.5227 percent.

M. Distribution O&M Expense

FPUC has included \$4,987,655 per books in distribution O&M expense in its 2025 projected test year. After applying (\$975,504) in adjustments for tree trimming and inspections related to the Storm Protection Plan, FPUC's included distribution O&M expense is \$4,012,151. The distribution O&M expense is based on directly projecting known distribution O&M expenses, including costs associated with the engineering and supervision of FPUC's proposed plant improvement projects and increasing historic test year distribution O&M expenses for inflation and customer growth, consistent with FPUC's prior base rate proceedings. These costs reflect the addition of an Instrumentation and Measurement Control (IMC) Technician in both FPUC's Northeast and Northwest territories, and the restructure of the Supervisor of Engineering's departmental duties, which resulted in a salary allocation to electric expense.

¹¹⁴ Witness Devon Direct Testimony, Page 16, Lines 1-4, Document No. 08589-2024.

¹¹⁵ Response No. 13 in Staff's Nineteenth Set of Data Requests, Document No. 10367-2024.

¹¹⁶ Response No. 12 in Staff's Eleventh Set of Data Requests, Document No. 09904-2024.

¹¹⁷ Document No. 08594-2024.

FPUC indicated that the IMC technicians are the personnel that are primarily responsible for the operation and maintenance of substations. The responsibilities of these positions include conducting inspections, performing necessary switching activities, collecting substation load readings, documenting relay operations, equipment maintenance activities, substation battery maintenance, substation security, ensuring the substations are maintained in a clean and orderly manner, and ensuring specialized work by contractors is completed efficiently and assisting when needed. The more routine activities, which are the majority of the tasks in the substations, will be completed by the IMC Technicians, while more specialized activities will be conducted by contractors, with the oversight of the IMC Technicians.

Both FPUC's Northeast and Northwest territories already had one IMC Technician; however, FPUC indicated that this position was responsible for both substation and metering related duties, which resulted in the workload exceeding FPUC staff's capacity.¹¹⁸ With the addition of a new IMC Technician position in both territories, the duties will be split between the positions. As such, one IMC Technician will be responsible for substation related duties, while the other IMC Technician will be responsible for metering related duties. The Northeast IMC Technician position was filled in the third quarter of 2023, and the Northwest IMC Technician position was filled in the third quarter of 2024, with a base hourly salary of \$47.43 per hour each, which is the same salary as the original IMC Technicians. Additionally, costs related to Company-provided substation maintenance, annual training, and equipment and supplies, totaling approximately \$73,000, have been included for the new Northwest IMC Technician due to the acquisition of the substation assets discussed above.

The Supervisor of Engineering's departmental duties were restructured in 2024, which resulted in a 39.2 percent salary allocation to electric expense rather than the previous salary allocation of 100 percent to capital expense. FPUC indicated that this allocation is due to the additional internal engineering costs related to additional substation maintenance planning, with more focus on vegetation management, transmission/distribution relay modifications, and monitoring feeder loading. The total included in the 2025 projected test year for the salary allocation to electric expense is \$61,041.

We have reviewed the distribution O&M expense and find that the overall distribution O&M expense is reasonable, including the costs associated with the engineering and supervision of plant improvement projects due to the increased workload associated with the acquisition and replacement/rebuild of the substation assets, and increased position responsibilities. Given the removal of additional Storm Protection Plan expenses, we find that the 2025 projected test year O&M expense shall be reduced by (\$76,670).¹¹⁹ With that adjustment we find that FPUC's distribution O&M expense should be \$3,935,481 for the 2025 projected test year.

N. Transmission O&M Expense

FPUC has included \$144,837 in transmission O&M expense in its 2025 projected test year. Consistent with FPUC's prior base rate proceedings, this amount is based on directly

¹¹⁸ Response No. 23 in Staff's Sixth Data Request, Document No. 09794-2024.

¹¹⁹ Response No. 1A in Staff's Fifteenth Data Request, Document No. 10110-2024.

projecting known transmission O&M expenses, and increasing historic test year transmission O&M expense for inflation and customer growth. We find that FPUC's transmission O&M expense of \$144,837 is reasonable and shall be included in its 2025 projected test year.

O. Total O&M Expense

The Company's proposed O&M expense per books is \$20,084,163. Combined with the net operating income adjustments of (\$3,838,470), this results in an adjusted jurisdictional O&M expense of \$16,245,692.¹²⁰ With the removal of additional Storm Protection Plan expenses discussed above, we find that the 2025 projected test year O&M expense shall be reduced by (\$76,670).¹²¹ This results in an adjusted test year O&M expense of \$16,169,022 which we find to be appropriate.

VIII. Depreciation Expense

The purpose of depreciation expense is to allocate and ultimately recover the costs of long-lived (i.e., generally greater than one year) assets over their respective useful lives. Alternatively stated, depreciation ensures that the cost of an asset is spread over its useful life, which matches the expense to the time period in which the asset is "used and useful" in providing utility service. Further, accounting for depreciation helps to provide an accurate picture of the Company's financial performance by recognizing that assets lose value over time due to factors such as "wear and tear," obsolescence, or age.

FPUC's proposed annual depreciation expense for the 2025 test year is \$5,584,900 per books.¹²² After accounting for its proposed adjustments, FPUC's level of depreciation expense is \$5,280,274 for the 2025 projected test year. The Company calculated its depreciation expense using the appropriate rates as prescribed by Commission Order No. PSC-2023-0384-PAA-EI.¹²³

We have reviewed the Company's depreciation expense proposals as contained in the MFRs and observed eight accounts with anomalous expense results. The specific accounts are as follows: Account 303.2 - Intangible Plant CIS, Account 350.2 - Rights of way, Account 352 - Structures & Improvements, Account 353 - Station Equipment, Account 354 - Towers & Fixtures, Account 355 - Poles & Fixtures - Concrete, Account 355 - Poles & Fixtures-SPP, and Account 365 - Overhead Conductors & Devices. The Company has indicated that certain adjustments to the MFRs were necessary. These adjustments were provided in FPUC's Responses to Staff's Seventh Set of Data Requests.¹²⁴ Having reviewed the adjustments we find them to be appropriate. Further, additional retirement-related adjustments reducing depreciation expense were performed for Account 391.1 - Computer and Periphery and Account 391.2 -

¹²⁰ Document No. 08594-2024.

¹²¹ Response No. 1A in Staff's Fifteenth Set of Data Requests, Document No. 10110-2024.

¹²² Document No. 08594-2024.

¹²³ Order No. PSC-2023-0384-PAA-EI, issued December 21, 2023, in Docket No. 20230079-EI, *In re: Petition for approval of 2023 depreciation study by Florida Public Utilities*.

¹²⁴ *Id.*

Computer Hardware.¹²⁵ After accounting for these changes, the amended adjusted annual depreciation expense for the 2025 test year is \$5,518,536.

We have further adjusted \$211,288 from the Company's request related to the recovery of the substation assets discussed and approved above. Additionally, we adjusted depreciation expense by \$187,357 associated with the Company's proposed two-way communication system. Thus, we find that the jurisdictional adjusted level of depreciation expense for the 2025 test year is \$5,119,891.

IX. Taxes Other Than Income

Taxes Other Than Income (TOTI) taxes generally consist 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 total 2025 projected test year Company proposed TOTI per books is \$9,376,855. Combined with net operating income adjustments of (\$7,019,075), results in an adjusted jurisdictional TOTI amount of \$2,357,780.¹²⁶ The Company provided the projected 2025 property tax expense calculations.¹²⁷ The forecasted 2025 property tax increased relative to prior 2024 year as a result of forecasted increases to 2025 average plant in service. We find that the increased forecast for average plant to be reasonable; thus, the forecasted 2025 property tax calculations, including the previously discussed adjustments, are reasonable and are approved. Therefore, the adjusted jurisdictional TOTI amount for the 2025 test year is \$2,214,461.

X. Income Tax Expense

This is a fall-out issue. On MFR Schedule C-22, FPUC calculated an adjusted jurisdictional Income Tax expense of (\$1,970,618) for the 2025 projected test year.¹²⁸ We have reviewed the Company's proposed interest expense and observed anomalous results which led to discovery on the topic. In FPUC's Responses to Staff's Ninth Data Request, the Company determined that adjustments to the proposed MFRs were necessary. This resulted in the as-filed revenue requirement being overstated by \$732,820 and an Income Tax expense decrease of \$541,193.¹²⁹

Based on adjustments to storm hardening revenues and expenses and depreciation expenses, along with corresponding adjustments to all NOI issues, we approve a total decrease in 2025 Income Tax expense of \$388,867, resulting in a total Income Tax expense, including interest synchronization, of \$2,359,485 for the 2025 projected test year.

¹²⁵ Document No. 10111-2024.

¹²⁶ Document No. 08594-2024.

¹²⁷ Response No. 5 in Staff's Nineteenth Data Request, Document No. 10367-2024.

¹²⁸ Document No. 08594-2024.

¹²⁹ Document No. 09841-2024.

XI. Net Operating Income

This is a fall-out issue consisting of the difference between projected test year revenues and Total Operating Expense. On MFR Schedule C-1 (2025), FPUC requested a total Net Operating Income of \$991,558 for the 2025 projected test year.¹³⁰ Based on the previous adjustments discussed above, we approve an increase of \$845,785, resulting in a total Net Operating Income of \$1,837,342 for the 2025 projected test year.

XII. Revenue Expansion Factor and
Net Operating Income Multiplier

On MFR Schedule C-44, FPUC calculated a net operating income multiplier of 1.3477.¹³¹ This multiplier is based on a revenue expansion factor of 74.2015 percent, formulated using a 0.0848 percent factor for regulatory assessment fees, a 0.5227 percent bad debt rate, a 5.5 percent state income tax, and a 21.0 percent Federal Income Tax rate. The net operating income multiplier calculation is shown in Table 27.

**Table 27
NOI Multiplier**

Description	Value
Revenue Requirement	100.0000%
Less Regulatory Assessment Fee	0.0848%
Less Staff Calc. Bad Debt Rate	<u>0.5227%</u>
Net Before Income Taxes	99.3925%
Less State Income Tax @ 5.5%	5.4666%
Net Before Federal Income Tax	94.9259%
Less Federal Income Tax @ 21.0%	<u>19.7244%</u>
Revenue Expansion Factor	<u>74.2015%</u>
NOI Multiplier (100/74.424)	<u>1.3477</u>

Source: MFR Schedule C-44.

We find that the appropriate revenue expansion factor is 74.2015 percent and net operating income multiplier is 1.3477 for the 2025 projected test year, including the elements and rates discussed in the analysis portion of this order.

XIII. Operating Revenue Increase

This is a fall-out issue. In its original filing, FPUC requested a total operating revenue increase of \$12,593,450 for the 2025 projected test year.¹³² After accounting for changes in

¹³⁰ Document No. 08594-2024.

¹³¹ Document No. 08594-2024.

¹³² Document No. 08592-2024.

service charges and other revenues of (\$164,495), the Company's proposed increase in base rate revenues is \$12,428,955.

Based on our previous adjustments to Plant in Service, Cost of Capital, and Net Operating Income, we approve an operating revenue increase of \$9,839,666 for the 2025 projected test year. After accounting for changes in service charges and other revenues of (\$164,495), our proposed increase in base rate revenues is \$9,675,171.

XIV. Rates

A. Cost of Service Methodology

FPUC is a non-generating utility, therefore, there are no production costs included in the cost of service study. The purpose of a cost of service methodology is to perform three activities. First, it functionalizes costs into transmission, distribution, and customer categories. Second, these functionalized costs are separated into classifications based on the utility service being provided. Since FPUC has no production costs, there are only two principal classifications of costs: (1) demand costs which are costs that vary with the kW demand imposed by the customer and (2) customer costs which are costs that are directly related to the number of customers served. With production costs, typically there would also be an energy allocation. As described in the direct testimony of witness Taylor, the results of the cost of service study are utilized to determine the relative cost to serve each rate class, help determine the individual classes' revenue responsibility, and provide guidance with rate design.

Witness Taylor states that the proposed cost of service study has been prepared to align with the cost of service study used in FPUC's previous rate case filing. FPUC explained that in MFR Schedules E-11 and E-17 the demand allocation factors used in FPUC's cost of service study are based on Gulf Power Company's (now part of Florida Power & Light Company) load research results. FPUC stated that as a small electric system and because of its non-generating status, the Company has not been required to conduct load research. Due to the similar geography, we find that using Gulf Power Company's load research data is appropriate and consistent with the MFRs filed in FPUC's 2014 rate case.

The appropriate cost of service study methodology utilizes the 12 Monthly Coincident Peak (CP) method for the allocation of transmission costs; non coincident peak and customer maximum demand for distribution plant; and classifies only the meter, service drop, and customer-service components of the distribution system as customer-related. The appropriate cost of service study is contained in MFR Schedule E and is consistent with FPUC's last rate case filing.

B. Allocation of Revenue Requirement

FPUC witness Taylor described in direct testimony how the Company allocated the proposed revenue requirement increase among the rate classes. While the Company considered several options, including setting revenues to the cost to serve each class, FPUC has proposed to allocate the revenue requirement using a target system multiplier at equal rates of return. Under the proposed allocation, GS, GSD, and GSLD would receive an increase 1.35 times the system average increase, GSLD1 and Lighting would receive an increase of 0.54 times the system

average increase, and the remaining revenue increase was apportioned to the RS class. This resulted in an increase of 0.86 times the system average increase for RS customers.

MFR Schedule E-8 demonstrates how the proposed allocation of the revenue increase moves each customer class closer to parity, where the class rate of return is equal to the system rate of return. As a result of limited base rate increases, FPUC's customer classes at present rates are far outside of parity, as shown by the present rate of return index on MFR Schedule E-8. Under the Company-proposed allocation, each customer class would move closer to parity with the overall system rate of return. Furthermore, FPUC has complied with Commission practice where each class has not received more than 1.5 times the system average increase nor has any class received a decrease. Table 2 in the direct testimony of witness Taylor provides the proposed revenues by rate division and demonstrates how no class has received an increase greater than 1.5 times the system average increase. Based on the information provided, we find that FPUC's proposed allocation of the revenue increase is appropriate.

Based on the above, we find that the appropriate allocation of the change in revenue requirement, after recognizing any additional revenues realized in other operating revenues, shall 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 increase shall be allocated to the rate classes in a manner that moves the class rate of return indices as close to parity as practicable based on the approved cost allocation methodology, subject to the following constraints: (1) no class should receive an increase greater than 1.5 times the system average percentage increase in total, and (2) no class should receive a decrease.

C. Customer Facilities Charge

The customer facilities charges, in combination with the demand charges and the energy charges, are designed to allow FPUC to recover the total revenue requirement that we have approved. The proposed customer facilities charges in Attachment B reflect the revenue requirement and cost of service methodology that we previously approved on March 4, 2025. Therefore, we approve the customer facilities charges as stated in the tariffs in Attachment B to this order.

D. Demand Charges

The demand charges, in combination with the customer facilities charges and the energy charges, are designed to allow FPUC to recover its total revenue requirement. The proposed demand charges stated in the tariffs in Attachment B correctly reflect the revenue requirement and cost of service methodology previously approved by us. For that reason, we hereby approve the demand charges stated in the tariffs in Attachment B to this order.

E. Energy Charges

The energy charges, in combination with the customer facilities charges and demand charges, are designed to allow FPUC to recover its total revenue requirement. The proposed energy charges as stated in the tariffs in Attachment B to this order correctly reflect the revenue requirement and cost of service methodology previously approved by us and are hereby approved.

F. Standby Service

The standby service tariff is applicable only to customers who are self-generators with the capability to meet their entire electric power requirements and require backup or maintenance service on a firm basis. The standby service tariff is not applicable to self-generating customers who require supplemental service. Witness Haffecke stated in his direct testimony that FPUC currently has one large industrial customer taking service under the standby service tariff since 2012.

Witness Haffecke explained that the single large industrial customer is more suited to be served by the GLSD 1 tariff, based upon routine requests for power beyond what is contemplated by the standby service tariff. Witness Haffecke further stated that upon moving this customer to the more appropriate rate class, no customers will be taking service under the standby service tariff, and since the Company has had no other requests for standby service over the life of the tariff, the Company believes that it is administratively efficient to close this tariff. Therefore, FPUC proposes to delete the standby service tariff and move the single industrial customer to the GLSD 1 tariff. The GLSD 1 tariff is applicable to customers who contract for at least 5,000 kilowatts of service and take service at transmission level.

FPUC stated that it informed the industrial customer of the proposal and currently is working with the customer to answer the customer's concerns and questions.¹³³ Additionally, FPUC stated that it had several conversations with the large industrial customer taking service under the standby service, and that the customer is in favor of being moved to the GLSD-1 rate class. FPUC believes that there are no outstanding customer concerns.¹³⁴

Based on the above, we approve FPUC's proposal to delete standby service. The standby service tariff shall be closed once our decision in this docket has become final.

G. Temporary Service Charges

FPUC, upon request by a customer, will supply temporary electric service when the Company's distribution system is near the requested location. The Company will provide temporary service via an overhead or underground pole and will provide additional poles as requested for additional charges. The temporary service charges are shown on proposed Original Sheet No. 6.023. The proposed service charges will enable the Company to recover its costs related to temporary services requested by its customers.

Table 28 below shows the current and Company temporary service charges.

¹³³ Response No. 12 to Staff's Third Data Request, Document No. 09593-2024.

¹³⁴ Response No. 1 to Staff's Twenty Fourth Data Request, Document No. 00202-2025.

Table 28
Temporary Service Charges

Charge Type	Current	Proposed
Installing and Removing Temporary Service	\$230	\$415
Underground Service	\$200	\$250
Pole with Overhead Service	\$395	\$835
Pole with Underground Service	\$560	\$1,000

Source: Schedules E-14-Tariff Sheet No. 6.023.

When the requested temporary service requires multiple temporary poles and/or extensive facilities, the Company will estimate the cost of installing and removing the temporary facilities and provide that cost estimate to the customer. The customer has the option to later replace the temporary service with permanent service, in which case the Company will remove the temporary service facilities and install a meter, service drop, and other facilities as may be necessary.

Based on the above, we hereby approve the proposed modifications to the temporary service charges.

H. Deposit Amounts

The current and revised deposit amounts are shown on Original Sheet No. 6.012. This tariff is applicable to customers seeking undergrounding of existing or newly planned electric distribution facilities by the Company. Underground facilities include, but are not limited to, distribution facilities consisting of conductors, switches, and transformers. The purpose of the deposit is to approximate the engineering costs for underground facilities associated with preparing the requested estimates. The non-refundable deposit must be paid to the Company to initiate the estimating process. The deposit is applied towards the calculation of the facility charge required for the installation of underground distribution facilities.

Once the deposit from a customer is received, the Company will begin preparing a binding cost estimate to construct or convert overhead facilities to underground facilities. If the applicant does not enter into a contract for the installation of the requested underground facilities within 180 days of providing the binding cost estimate by the Company, the deposit shall be forfeited, and the binding cost estimate provided to the customer shall be considered expired.

Table 29
Undergrounding Deposit Amounts

	Current	Proposed
New Construction (Excluding New Residential Subdivisions)		
Facilities Classification	Deposit Amount (per overhead primary mile)	
Urban Commercial	\$3,715	\$4,540
Urban Residential	\$2,565	\$3,555
Rural Residential	\$1,946	\$3,263
Conversions		
Facilities Classification	Deposit Amount (per overhead primary mile)	
Urban Commercial	\$5,750	\$6,815
Urban Residential	\$4,511	\$5,330
Rural Residential	\$3,273	\$4,895
Low Density Subdivision	\$18.00 per lot	\$64.00 per lot
High Density Subdivision	\$17.00 per lot	\$42.00 per lot

Source: First Revised Sheet No. 23 (Proposed Original Sheet No. 6.012).

The proposed binding cost estimates approximates the engineering costs for underground facilities and also reflect the changes in labor and transportation costs since FPUC’s last rate case in 2014.¹³⁵ FPUC witness Haffecke’s Exhibit WH-4 includes the updated construction and conversion labor costs. The currently approved and the proposed deposits for binding cost estimates are shown in Table 29 above.

Based on the above, the proposed modifications to the binding cost estimates for new underground construction and overhead conversions are approved. The approved binding cost estimates reflect the changes in labor and transportation costs since FPUC’s last rate case in 2014.

¹³⁵ Response 3 in Staff’s Twelfth Data Request, Document No. 09906-2024 and Exhibit WH-4 in witness Haffecke’s direct testimony.

I. Miscellaneous Service Charges

The Miscellaneous Service Charges are fixed charges that are paid when a specified activity occurs, such as the initial connection of a residential or business, a change of account, or a late payment. The Miscellaneous Service Charges are designed to recover the billing, personnel, and other overhead costs associated with the specific charge.

Witness Grimard sponsored the Miscellaneous Service Charge with Exhibit WG-1. Our approved Miscellaneous Service Charges are contained in Table 30 which also shows FPUC's present and proposed charges.

Table 30
FPUC Miscellaneous Service Charges

Miscellaneous Service Charges	Current Amount (\$)	Proposed Amount (\$)	Commission Approved Amount (\$)
Initial establishment of service	61	125	125
Re-establishment of service or Change Account	26	45	45
Temporary disconnect then reconnection of service	65	81	81
Reconnection - service after disconnection for rule violation (normal hours)	52	70	70
Reconnection - service after disconnection for rule violation (after normal hours)	178	325	325
Connect and then disconnect temporary service	85	135	135
Collection charge	16	50	50

Source: FPUC Exhibit WG-1.

The cost support for the increase in miscellaneous service charges is shown in Schedule E-7 of the MFRs. Schedule E-7 illustrates that the increased rates are largely driven by inflation over 10 years, which effects increases in the cost of labor and materials. FPUC explained that transportation costs have increased due to a significant rise in vehicle costs, fuel, and insurance.¹³⁶ The increase in cost is also due to a switch from service labor to construction labor and the use of bucket trucks over pickup trucks. Bucket trucks are required by the linemen to construct and establish services. To reflect the work done more accurately, FPUC changed the charges on bills to more accurately reflect the type of services being performed. For these reasons, the proposed Miscellaneous Service Charges as contained in Table 28 are approved.

¹³⁶ Response No. 8 to Staff's Third Data Request, Document No. 09593-2024.

J. Non-Firm Energy Program-Experimental

Initially approved in 2019 as a pilot, which expired on December 31, 2020, the Non-Firm Energy Program was designed for FPUC to purchase non-firm energy from FPL and sell the non-firm energy to qualifying industrial customers.¹³⁷ By Order No. PSC-2022-0064-TRF-EI, the program was reinstated permanently to include all eligible General Service Large Demand (GSLD), GSLD-1, or standby customers that own dispatchable self-generation.¹³⁸ Currently, there are two customers that qualify for the program.

FPUC witness Haffecke stated in direct testimony that the pilot program was created to incentivize qualifying customers to purchase more power from the grid on a consistent basis to increase the overall load factor. By increasing the system load factor, FPUC intended to reduce the purchased power costs recovered from the general body of ratepayers. Witness Haffecke further stated that while the participating customers did increase their purchase of power somewhat, the increase was not to the extent FPUC needed to achieve the overall pricing benefits contemplated. The additional power purchases did not reduce the system peak demand and as a result, the power costs were still included in the regular monthly purchased power billing, which is recovered by the general body of ratepayers.

As such, FPUC has concluded that the Non-Firm Energy program did not meet expectations and does not provide the Company or the general body of ratepayers any benefits. If approved, the program would close to new customers and expire within 90 days of written notice by FPUC to participating customers and expire in its entirety by September 1, 2025. Based on these facts, we find that it is reasonable to close the program because the program has not benefited the general body of ratepayers as intended.

K. Technology Cost Recovery Rider

As explained in the testimony of FPUC witness Napier, the Company has requested approval of a rider mechanism to recover the cost of newly implemented technology, including a return on the investment and additional operating costs. The TCRR would allow the Company to continue to make significant investments in technology to modernize its current platform and to lay the foundation for technological upgrades. In addition, FPUC witness Napier stated the TCCR would provide certainty in regard to the recovery of its investment as well as ultimately reduce costs for customers. The proposed cost recovery mechanism is based on a 12-month projected recovery period from January 1 to December 31. The Company chose this period to be consistent with its other annual filings such as fuel, conservation, and storm protection cost recovery clause dockets.¹³⁹ FPUC proposes to file its first TCRR with us at least 60 days prior to the TCRR going into effect and refile on an annual basis at least 60 days prior to the January 1 effective date.

¹³⁷ Order No. PSC-2019-0432-TRF-EI, issued October 22, 2019, in Docket No. 20190132-EI, *In re: Petition for authority for approval of non-firm energy pilot program and tariff by Florida Public Utilities Company.*

¹³⁸ Order No. PSC-2022-0064-TRF-EI, issued February 18, 2022, in Docket No. 20210180-EI, *In re: Petition for authority to reinstate the non-firm energy program and tariff, Florida Public Utilities Company.*

¹³⁹ Response No. 6 in Staff's Eighth Data Request, Document No. 09790-2024.

FPUC stated that at the time of the filing of its petition, all the TCRR programs and projects have not been finalized. FPUC has not provided a specific term of the TCRR nor the initial implementation date of the TCRR. As a result, there are no monthly cost recovery factors or costs to be voted on at this time. Additionally, “the Company is still determining the scope and timing of the Enterprise Resource Planning (ERP) project”¹⁴⁰ which is one of the technology advancements that would be recovered through the TCRR. The ERP is expected to be implemented in 2026. The TCRR is being presented as a way to avoid single-issue rate cases and regulatory lag. FPUC notes that processing a full rate proceeding could add upwards of \$1.5 million of additional costs associated with rate case expenses.¹⁴¹ In response to Staff’s First Data Request No. 19, FPUC states that if the proposed TCRR is not approved and revised costs are not included in this rate case, the Company most likely would file a limited proceeding to recover the incurred ERP costs.

The ERP system is designed to integrate the general ledger with the CIS which was implemented in 2024 and proposed to be included in base rates in this proceeding. However, there are continuing costs to fine tune the implementation of the new CIS billing system.¹⁴² Additionally, the Company is considering the integration of a Human Resource Information System (HRIS) into the overall ERP system. The Company estimated the cost of the ERP systems to be between \$50 million to \$70 million.¹⁴³ FPUC witness Gadgil characterizes the ERP as a way to integrate and streamline CUC’s core finance, project management, asset management, and procurement processes.¹⁴⁴ The ERP system component is the only project the Company anticipates recovering via the TCRR in the near term. FPUC asserts that the entire project, including HRIS will benefit all of CUC and a portion of the total costs would be allocated to FPUC electric division.¹⁴⁵ The Company states that the proposed Rider would allow it to implement beneficial and prudent technology investments on a more regular basis over time benefitting customers with additional service features and capabilities with technology improvements, which are evolving rapidly.

The Company asserts that the proposed TCRR is similar to the Gas Reliability Infrastructure Program (GRIP), Gas Utility Access and Replacement Directive (GUARD), and Safety, Access, and Facility Enhancement (SAFE) programs, although the underlying purpose differs.¹⁴⁶ We disagree with this characterization because the above listed gas safety riders were a result of Pipeline and Hazardous Safety Administration regulations. TCRR is not a federally mandated Rider nor a response to a safety risk. In the order approving FPUC’s GRIP program, we found that “replacement of bare steel pipelines is in the public interest to improve the safety

¹⁴⁰ Response No. 1 in Staff’s Third Data Request, Document No. 09593-2024.

¹⁴¹ Response No. 3 in Staff’s Eighth Data Request, Document No. 09790-2024.

¹⁴² Response Nos. 8 & 10 in Staff’s Eighth Data Request, Document No. 09790-2024.

¹⁴³ Response No. 5 in Staff’s Eighth Data Request, Document No. 09790-2024.

¹⁴⁴ Witness Gadgil Direct Testimony, Page 16, Lines 5-6, document No. 08588-2024.

¹⁴⁵ Response No. 3 in Staff’s Eighteenth Data Request, Document No. 10281-2024.

¹⁴⁶ Response No. 4 in Staff’s Third Data Request, Document No. 09593-2024.

of Florida's natural gas infrastructure, thereby reducing the risk to life and property.”¹⁴⁷ In the order approving Florida City Gas's SAFE program, we stated that the SAFE program “will serve to improve safety, reduce potential damage to property, and impede theft.”¹⁴⁸

In the GUARD program proposed by FPUC, we approved the components of the GUARD program that “should enhance the safety and accessibility of the natural gas distribution and denied the reliability program components because they are part of the utility's normal operations and therefore more appropriately addressed through traditional ratemaking processes.”¹⁴⁹

In 2021 we denied Utilities Inc. of Florida's (UIF) proposed Sewer and Water Improvement Mechanism (SWIM), which would allow UIF to recover the revenue requirement for the replacement of aging infrastructure through an annual increase in base rates. We found that UIF had provided very little evidence to support a finding that the SWIM should be approved and that “UIF has failed to meet its burden of proof to support the SWIM program.”¹⁵⁰ Similarly, FPUC has provided very little detail regarding projected costs, bill impacts, or specific start or completion dates for the proposed Rider.

As discussed above, the Rider is not finalized, is not measurable, is not quantifiable at this time, and its implementation date is beyond the test year. Based on our review, once costs and implementation date are finalized, the technology upgrades would be part of the Company's normal operations and are more appropriately addressed through traditional ratemaking processes such as through a petition for a limited proceeding or base rate proceeding.

For the reasons stated above, the new TCRR and associated Tariff Sheets (Original Sheet Nos. 7.027 through 7.029) are denied.

L. Hurricane Michael Storm Recovery Surcharge

Currently, the Hurricane Michael storm recovery surcharge is a cents per kilowatt-hour (kWh) rate applicable to all rate classes. The GSLD 1 rate class is applicable to commercial and industrial customers contracting for at least 5,000 kW of electric service. The GSLD 1 base rates are calculated using on base transmission demand and excess reactive demand and do not include an energy charge.¹⁵¹ FPUC explained that the proposal was prompted by GSLD 1 customers

¹⁴⁷ Order No. PSC-12-0490-TRF-GU, Issued September 24, 2012, in Docket No. 20120036-GU, *In re: Joint petition for approval of Gas Reliability Infrastructure Program (GRIP) by Florida Public Utilities Company and the Florida Division of Chesapeake Utilities Corporation.*

¹⁴⁸ Order No. PSC-15-0390-TRF-GU, issued on September 15, 2015, in Docket No. 20150116-GU, *In re: Petition for approval of safety, access, and facility enhancement program and associated cost recovery methodology, by Florida City Gas.*

¹⁴⁹ Order No. PSC-2023-0235-PAA-GU, issued August 15, 2023, in Docket No. 20230029-GU, *In re: Petition for approval of gas utility access and replacement directive, by Florida Public Utilities Company.*

¹⁵⁰ Order No. PSC-2021-0206-FOF-WS, issued June 4, 2021, in Docket No. 20200139-WS, *In re: Application for increase in water and wastewater rates Charlotte, Highlands, Lake, Lee, Marion, Orange, Pasco, Pinellas, Polk, and Seminole Counties, by Utilities, Inc. of Florida.*

¹⁵¹ See page 22 of Document No. 08582-2024.

using less regular service and more non-firm energy usage through the Non-Firm Energy tariff.¹⁵² As a result, less storm revenue was collected than initially projected in the original Hurricane Michael docket.

There are currently two GSLD 1 customers on FPUC's system. FPUC stated that the customers are aware of the proposed change.¹⁵³ Furthermore, FPUC argued that if the customers' total usage was to continue at the current level of both their firm and non-firm usage after expiration of the non-firm tariff, this change will benefit the customers.¹⁵⁴

FPUC has proposed an annual recovery of \$190,208 to be allocated across the GSLD 1 rate class. The total annual recovery of \$190,208 from GSLD 1 customers is consistent with the recovery amount previously allocated to GSLD 1 customers, as originally approved by us in Order No. PSC-2020-0347-AS-EI.¹⁵⁵ FPUC stated that the change from a variable rate to a fixed charge will have no impact on the total recovery of the surcharge.¹⁵⁶

In his direct testimony, witness Haffecke also stated that the bills are currently being manually generated, but with this change of the surcharge future bills are going to be automated with the implementation of the new CIS system. Furthermore, witness Haffecke argued that the change from a variable charge to a fixed charge for GSLD 1 customers will have no impact on the total recovery of the surcharge.¹⁵⁷

For these reasons, we approve FPUC's proposal to recover the Hurricane Michael storm recovery surcharge from GSLD-1 customers as a fixed charge, as opposed to a variable energy charge. Recovery of Hurricane Michael costs through a fixed charge should not impact the total recovery of the surcharge.

M. Effective Date

Pursuant to Section 366.06(4), F.S., FPUC, as of the date of our vote on rates, is entitled to place its requested rates into effect, subject to refund, upon notice to the Commission and upon filing the appropriate tariffs. FPUC requested \$12,428,955 in base rate revenues. On March 4, 2025, we approved rate base revenues of \$9,675,171, a reduction of \$2,753,784.

That being the case, FPUC is entitled to place the PAA rates approved by us into effect, subject to refund, on the date of our vote approving the rates, March 20, 2025. Should no protest be timely filed, FPUC shall then be authorized to release the security holding the rates subject to refund upon the expiration of the protest period and issuance of a consummating order. Should a

¹⁵² Responses to Staff's Thirtieth Data Request, Response No. 1, Document No. 00394-2025.

¹⁵³ Responses to Staff's Thirtieth Data Request, Response No. 4, Document No. 00394-2025.

¹⁵⁴ *Id.*

¹⁵⁵ Order No. PSC-2020-0347-AS-EI, issued October 8, 2020, in Docket No. 20190156-EI, *In re: Petition for a limited proceeding to recover incremental storm restoration costs, capital costs, revenue reduction for permanently lost customers, and regulatory assets related to Hurricane Michael.*

¹⁵⁶ Responses to Staff's Thirtieth Data Request, Response No. 3, Document No. 00394-2025.

¹⁵⁷ See pages 22 and 23 of Document No. 08582-2024.

protest be filed, the PAA rates shall remain in effect, subject to refund, pending the resolution of the case.

Alternatively, FPUC may implement the PAA rates approved by us on March 20, 2025, upon the expiration of the PAA protest period and issuance of a consummating order.

FPUC has requested that the PAA rates and charges, as stated in Attachment B to this order, go into effect on March 20, 2025, the date of our vote approving final rates and charges. FPUC will provide its customers with notice of the rate base revenue approved by us and the proposed PAA rates and charges associated with the approved rate base revenue increase. This notice will be posted to FPUC's website prior to the March 20, 2025 Special Agenda and mailed to the customers.

Based on the above, we find that appropriate date to implement the approved revised rates and charges, as stated in Attachment B to this order, is March 20, 2025.

N. Tariffs

We have reviewed the revised tariffs in Attachment B to this order and find that they have been appropriately revised to reflect the revenue requirement approved by us on March 4, 2025. Therefore, we hereby approve the revised tariffs as stated in Attachment B to this order.

O. Interim Refund

By Order No. PSC-2024-0441-PCO-EI, issued October 14, 2024, we authorized the collection of interim rates, subject to refund, pursuant to Section 366.071, F.S. The approved interim revenue requirement increase for FPUC was \$1,812,869.¹⁵⁸ The interim rates became effective for all meter readings occurring on or after 30 days from the Commission's vote on October 1, 2024.

In this proceeding, the test period for establishment of interim rates is the 12-month period ended December 31, 2023. FPUC's approved interim rates did not include any provisions for pro forma or projected operating expenses. The interim increase was designed to allow recovery of the lower limit of the currently authorized range for return on equity.¹⁵⁹ Because the interim revenue increase granted in Order No. PSC-2024-0441-PCO-EI is less than our approved final revenue requirement less adjustment for rate case expense, we find that no refund is required. Further, upon issuance of the final order in this docket, the corporate undertaking posted by FPUC shall be released.

¹⁵⁸ Order No. PSC-2024-0441-PCO-EI, issued October 14, 2024, in Docket No. 20240099-EI, *In re: Petition for rate increase by Florida Public Utilities Company*.

¹⁵⁹ Order No. PSC-14-0517-S-EI, issued September 29, 2014, in Docket No. 20140025-EI, *In re: Application for rate increase by Florida Public Utilities Company*.

P. Proof of Adjustment of Books and Records

FPUC shall file, within 90 days after the date of the final order in this docket, a description of all entries or adjustments to its annual report, rate of return reports, and books and records which will be required as a result of our findings in this rate case.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida Public Utilities Company's Petition for Approval of Rate Increase is granted in part as set forth herein. It is further

ORDERED that Florida Public Utilities Company is authorized to charge the revised rates and charges as set forth in Attachment B to this order. The approved rates shall remain in effect until we authorize a change in a subsequent proceeding. It is further

ORDERED that all matters contained in the attachments and schedules appended hereto are incorporated herein by reference. It is further

ORDERED that FPUC shall be required to file a rate calculation and associated tariff information for Commission staff's review and administrative approval following the in-service date of the substation project as discussed in Section IV.A. of this order. The Company shall limit the total recovery amount to the incremental cost identified in this proceeding, updated to reflect our vote on cost of capital and Net Income Multiplier issues. Further, for rate derivation purposes, FPUC shall develop a factor equal to the ratio of the incremental revenue requirement associated with the project and the forecasted base revenue from electricity sales used in developing the 2025 projected test year. The factor shall then be applied uniformly to FPUC's base rates by customer class. It is further

ORDERED that Florida Public Utilities Company 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 will be required as a result of our findings in this rate case. It is further

ORDERED that no refund of the interim rate increase is required. Upon issuance of the final order in this docket, the corporate undertaking shall be released. It is further

ORDERED that the provisions of this order, issued as proposed agency action, shall become final and effective upon the issuance of a consummating order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the "Notice of Further Proceedings" attached hereto. It is further

ORDERED that if a protest is filed within 21 days of the issuance of this order, the docket shall remain open and the tariffs shall remain in effect, with any revenues held subject to refund, pending resolution of the protest. If no protest is timely filed, this docket shall be closed upon the issuance of a consummating order.

By ORDER of the Florida Public Service Commission this 7th day of April, 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.

SBr

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.

As identified in the body of this order, our action herein, except for not requiring a refund of interim rates and requiring proof of adjustment of books and records, is preliminary in nature. Any person whose substantial interests are affected by the action proposed by this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Office of Commission Clerk, at 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on April 28, 2025. If such a petition is filed, mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing. In the absence of such a petition, this order shall become effective and final upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

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, 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 or the First District Court of Appeal in the case of a water or wastewater 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

ORDER NO. PSC-2025-0114-PAA-EI

DOCKET NO. 20240099-EI

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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.

Florida Public Utilities Company
Docket No. 20240099-EI
2025 Projected Test Year
13-Month Average Rate Base

Issue No.	Total Per Books	Company Adjustments	Company Adjusted	Commission Adjustments	Commission Adjusted
UTILITY PLANT					
	\$228,950,592				
		(7,684)			
		(24,147,089)			
6		11,472,643		(11,472,643)	
10				(939,615)	
	<u>\$228,950,592</u>	<u>(\$12,682,130)</u>	<u>\$216,268,462</u>	<u>(\$12,412,258)</u>	<u>\$203,856,204</u>
DEDUCTIONS					
	(\$77,701,596)				
14				(171,515)	
		1,954			
14		(2,924,052)		33,007	
14		(337,844)		337,844	
14				87,365	
	<u>(\$77,701,596)</u>	<u>(\$3,259,942)</u>	<u>(\$80,961,538)</u>	<u>\$286,701</u>	<u>(\$80,674,837)</u>
	<u>\$151,248,996</u>	<u>(\$15,942,072)</u>	<u>\$135,306,923</u>	<u>(\$12,125,557)</u>	<u>\$123,181,366</u>
CONSTRUCTION WORK IN PROGRESS					
	\$12,869,084				
		(3,827,550)			
		(731,263)			
16		(6,331,558)		6,331,558	
16				(88,462)	
	<u>\$12,869,084</u>	<u>(\$10,890,371)</u>	<u>\$1,978,713</u>	<u>\$6,243,096</u>	<u>\$8,221,809</u>
	<u>\$164,118,080</u>	<u>(\$26,832,444)</u>	<u>\$137,285,636</u>	<u>(\$5,882,461)</u>	<u>\$131,403,176</u>
WORKING CAPITAL ALLOWANCE					
	\$18,267,240				
		(398,941)			
		(1,331,206)			
		(3,769,633)			
	<u>\$18,267,240</u>	<u>(\$5,499,780)</u>	<u>\$12,767,460</u>	<u>\$0</u>	<u>\$12,767,460</u>
	<u>\$182,385,319</u>	<u>(\$32,332,223)</u>	<u>\$150,053,096</u>	<u>(\$5,882,461)</u>	<u>\$144,170,635</u>

Florida Public Utilities Company
 Docket No. 20240099-EI
 2025 Projected Test Year
 Supplemental Capital Structure - 13-MONTH AVERAGE

Company as filed	Company Total	Specific	System	Jurisdictional		Cost	Weighted
	Per Books	Adjustments	Adjusted	Capital Structure	Ratio	Rate	Cost Rate
Long Term Debt	\$1,331,883,955		1,331,883,955	56,888,413	37.91%	4.51%	1.71%
Short Term Debt	169,856,296		169,856,296	7,255,028	4.83%	5.81%	0.28%
Preferred Stock	0		0	0	0.00%	0.00%	0.00%
Common Equity	1,502,431,540	1,886,844	1,504,318,384	64,253,557	42.82%	11.30%	4.84%
Customer Deposits	4,001,097		4,001,097	4,001,097	2.67%	2.20%	0.06%
Deferred Income Taxes	13,206,708		13,206,708	13,206,708	8.80%	0.00%	0.00%
Regulatory Tax Liability	4,448,275		4,448,275	4,448,275	2.96%	0.00%	0.00%
ITC- Weighted Cost	0		0	0	0.00%	7.98%	0.00%
TOTAL	\$3,025,827,871	\$1,886,844	\$3,027,714,715	\$150,053,078	100.00%		6.89%

Commission Approved	Company Total	Specific	System	Jurisdictional		Cost	Weighted
	Per Books	Adjustments	Adjusted	Capital Structure	Ratio	Rate	Cost Rate
Long Term Debt	\$1,331,883,955		1,331,883,955	54,144,567	37.56%	4.51%	1.69%
Short Term Debt	169,856,296		169,856,296	6,905,103	4.79%	5.81%	0.28%
Preferred Stock	0		0	0	0.00%	0.00%	0.00%
Common Equity	1,502,431,540	1,886,844	1,504,318,384	61,154,478	42.42%	10.15%	4.31%
Customer Deposits	4,001,097		4,001,097	4,001,097	2.78%	2.20%	0.06%
Deferred Income Taxes	13,206,708	310,407	13,517,115	13,517,115	9.38%	0.00%	0.00%
Regulatory Tax Liability	4,448,275		4,448,275	4,448,275	3.09%	0.00%	0.00%
ITC- Weighted Cost	0		0	0	0.00%	7.41%	0.00%
TOTAL	\$3,025,827,871	\$2,197,251	\$3,028,025,122	\$144,170,635	100.00%		6.34%

Florida Public Utilities Company
 Docket No. 20240099-EI
 2025 Projected Test Year
 Net Operating Income

Issue No.	Operating Revenues	Purchased Power	O&M Other	Depreciation	Amortization	Taxes Other Than Income	Income Taxes	Deferred Income Taxes	Total Operating Expenses	Net Operating Income
Company Total per Books	\$98,256,853	52,150,543	20,084,163	5,584,900	8,093,606	9,376,855	(1,466,781)	1,988,078	95,811,363	2,445,490
Company Adjustments	(72,902,908)	(52,150,543)	(3,838,470)	(304,626)	(7,632,424)	(7,019,075)	(503,837)	0	(71,448,975)	(1,453,933)
Adjusted per Company	\$25,353,946	\$0	\$16,245,692	\$5,280,274	\$461,182	\$2,357,780	(\$1,970,618)	\$1,988,078	\$24,362,388	\$991,558
Commission Adjustments										
32 SPP Net Under Removal of Inspection Expense			(76,670)				19,432		(57,238)	57,238
43 Remove Company Substation Adjustment				(211,288)			53,551		(157,737)	157,737
43 Two-way Communication System Adj.				(187,357)			47,486		(139,871)	139,871
43 SPP Related Depreciation				(48,005)			12,167		(35,838)	35,838
43 Retirement-related Dep. Exp. Reductions				(5,596)			1,418		(4,178)	4,178
43 Updated Depreciation Expense				291,863			(73,973)		217,890	(217,890)
Interest Expense Calculation Error							(540,376)		(540,376)	540,376
Rate Case Expense Adjustment					(76,545)		19,400		(57,145)	57,145
Two-way Comm. Property Tax Adj.						(19,224)	4,872		(14,352)	14,352
Remove Substation Property Tax						(124,095)	31,452		(92,643)	92,643
Interest/Income Tax Synchronization							35,703		35,703	(35,703)
Total Commission Adjustments			(76,670)	(160,383)	(76,545)	(143,319)	(388,867)		(845,784)	845,784
Commission Adjusted NOI	\$25,353,946	\$0	\$16,169,022	\$5,119,891	\$384,637	\$2,214,461	(\$2,359,485)	\$1,988,078	\$23,516,604	\$1,837,342

Florida Public Utilities Company
Docket No. 20240099-EI
2025 Projected Test Year
Operating Revenue Requirement Increase Calculation

<u>Line No.</u>	<u>As Filed</u>	<u>Commission Adjusted</u>	
1	Jurisdictional Rate Base	\$150,053,096	\$144,170,635
2	Rate of Return	<u>6.89%</u>	<u>6.34%</u>
3	Required Net Operating Income (1)x(2)	10,336,088	9,138,522
4	Achieved Net Operating Income	<u>\$991,558</u>	<u>\$1,837,342</u>
5	Net Operating Income Deficiency (3)-(4)	9,344,530	7,301,180
6	Net Operating Income Multiplier	<u>1.3477</u>	<u>1.3477</u>
7	Operating Revenue Increase (5)x(6)	<u>\$12,593,450</u>	<u>\$9,839,666</u>
8	Increase in Service Charges and Other Revenues	164,495	164,495
9	Increase in Base Rate Revenues	<u>\$12,428,955</u>	<u>\$9,675,171</u>



F. P. S. C. ELECTRIC TARIFF

FIRST REVISED VOLUME NO. II

OF

FLORIDA PUBLIC UTILITIES COMPANY

FILED WITH

FLORIDA PUBLIC SERVICE COMMISSION

Communications concerning this Tariff should be addressed to:

Florida Public Utilities Company
208 Wildlight Avenue
Yulee, Florida 32097

Attn: Director of Regulatory Affairs

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MISCELLANEOUS GENERAL INFORMATION

Florida Public Utilities Company was incorporated under the Laws of Florida in 1924 and adopted its present corporate name in 1927.

It is principally engaged in the distribution and sale of natural gas and electricity. Its operations are entirely within the State of Florida.

The internet link to this Tariff is www.fpuc.com

General Florida office is located at:

208 Wildlight Avenue
Yulee, Florida 32097

Division offices are located at:

2825 Pennsylvania Avenue
Marianna, Florida 32446-4004

And

780 Amelia Island Parkway
Fernandina Beach, Florida 32034

Communications covering rates should be addressed to:

Florida Public Utilities Company
208 Wildlight Avenue
Yulee, Florida 32097

SYSTEM MAP

Northwest Florida Division System Map
Parts of Jackson, Calhoun County and Liberty Counties



SYSTEM MAP

Northeast Florida Division Service Map
Amelia Island located in Nassau County



TERRITORY SERVED

As indicated on the System Maps, two areas are served with electricity, both of which are located in the northern part of Florida.

The Northwest Florida Division serves various communities in Jackson, Calhoun and Liberty Counties.

The Northeast Florida Division serves Amelia Island, located in Nassau County.

TECHNICAL TERMS AND ABBREVIATIONS

When used in the rules and regulations or the rate schedules contained in this volume, the following terms shall have the meanings defined below:

- A. Company – Florida Public Utilities Company acting through its duly authorized officers or employees within the scope of their respective duties.
- B. Applicant – any person, firm, or corporation applying for electric service from the Company at one location.
- C. Customer – any person, firm, or corporation purchasing electric service at one location from the Company under Rules and Regulations of the Company.
- D. Service Classification
 - (1) Residential Service – service to Customer supplied for residential purposes in a single family dwelling unit or household. Residential service shall also apply to energy used in commonly owned facilities in condominium and cooperative apartment buildings 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 provided 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.
 - (2) Commercial Service – service to Customers engaged in selling, servicing, warehousing, or distributing a commodity, in some business activity or in a profession, or in some form of economic or social activity (offices, stores, clubs, hotels, etc.) and for purposes that do not come directly under another classification of service. A premise which might otherwise, except for business activity conducted thereon, be entitled to Residential Service shall be classified as Commercial unless that portion of said premise use solely for residential purposes is metered separately.
 - (3) Industrial Service – service to Customers engaged in a process which creates or changes raw or unfinished material into another form or product. (Factories, mills, machine shops, mines, oil plants, refineries, creameries, canning, and packing plants, shipyards, etc., i.e., in extractive, fabricating, or processing activities.)

TECHNICAL TERMS AND ABBREVIATIONS (Continued)

- E. Service Line – all wiring between the Company’s main line or substation transformer terminals and the point of connection to Customers service entrance.
- F. Single Service – one set of facilities over which Customer may receive electric power.
- G. KW or Kilowatt – one thousand (1,000) watts.
- H. KWh or Kilowatt-hour – one thousand (1,000) watt-hours.
- I. Energy – current consumed, expressed in kilowatt-hours.
- J. BTU or British Thermal Unit – the amount of heat required to raise the temperature of one (1) pound of water one degree Fahrenheit (1°F) at sixty degrees Fahrenheit (60°F).
- K. Horsepower - the nameplate rating of motors or its equivalent in other apparatus. For conversion purposes on horsepower shall be considered as equivalent to 0.75 kilowatts.
- L. Candlepower – one-tenth of the manufacturer’s rating in lumens.
- M. Connected Load – sum of the ratings of the electric power consuming apparatus connected to the installation or system, or part of either, under consideration.
- N. Demand – the load at the terminals of an installation or system averaged over a specified period of time. Demand is expressed in kilowatts, kilovolt-amperes, or other suitable units.
- O. Power Factor – ratio of kilowatts to kilovolt-amperes.
- P. Month – the period between any two (2) regular readings of Company’s meters at approximately thirty (30) day intervals.

RESERVED FOR FUTURE USE

INDEX OF RULES AND REGULATIONS

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RULES AND REGULATIONS

Applicable to Electric Service and Electric Rate Schedules

1. General

Company shall furnish service under its rate schedules and these Rules and Regulations as approved from time to time by the Florida Public Service Commission and in effect at this time. These Rules and Regulations shall govern all service except as specifically modified by the terms and conditions of the rate schedules or written contracts. Copies of currently effective Rules and Regulations are available at the office of Company.

Unless otherwise specifically provided in any applicable rate schedule or in a contract by or with Company, the term of any agreement shall become operative on the day the Customer's installation is connected to Company's facilities for the purpose of taking electric energy and shall continue for a period of one (1) year and continuously thereafter until cancelled by three (3) or more days' notice by either party.

2. Application for Service

An application for service will be required by Company from each Applicant. Such application shall contain the information necessary to determine the type of service desired and the conditions under which service will be rendered. If necessary, the application or contract for service shall be in writing.

The application or depositing of any sum of money by the Applicant shall not require company to render service until the expiration of such time as may be reasonable required by Company to determine if Applicant has complied with the provisions of these Rules and Regulations and as may reasonably be required by Company to install the required facilities.

3. Election of Rate Schedules

Optional rates are available for certain classes of Customers. These optional rates and the conditions under which they are applicable are set forth in Company's rate schedules.

Upon application for service or upon request, Applicant or Customer shall elect the applicable rate schedule best suited to his requirements. Company will assist in making such election but does not guarantee that Customers will be served under the most favorable rate schedule at all times. Company shall not be held

RULES AND REGULATIONS (Continued)

3. Election of Rate Schedules (Continued)

responsible to notify Customers of the most favorable rates schedule and will not refund the difference in charge under different rate schedules to the same class of service.

Upon notification of any material changes in Customer's installation or load conditions, Company will assist in determining if a change in rates is desirable, but unless required by substantial changes in the Customer's installation, not more than (1) such change in rates will be made within any twelve (12) month period.

Company will require a written contract with special guarantee from Applicants whose characteristics of load would require excessive investment in facilities of whose requirements for service are of a special nature.

4. Customer Deposits

A. Deposit Required

Unless credit is established in accordance with Section 4B, the Customer shall make a deposit. The amount of the deposit shall be calculated in conformity with the requirements of Section 366.05(1)(c), Florida Statutes, as follows:

- (1) For an existing account or premise, the total deposit may not exceed two (2) months of average actual charges, calculated by adding the monthly charges from the 12-month period immediately before the date any change in the deposit is sought, dividing this total by 12, and multiplying the result by 2. If the account or premise has less than 12 months of actual charges, the deposit shall be calculated by adding the available monthly charges, dividing this total by the number of months available, and multiplying the result by 2.
- (2) For a new service or premise request, the total deposit may not exceed two (2) months of projected charges, calculated by adding the 12 months of projected charges, dividing this total by 12, and multiplying the result by 2. Once the new Customer has had continuous service for a 12-month period, the amount of the deposit shall be recalculated using actual data. Any difference between the projected and actual amounts must be resolved by the Customer paying any additional amount that may be billed by the utility or the utility returning any overcharge.
- (3) A residential Customer may request the amount of the initial deposit be billed and paid in even installments over a period of two (2) month's for deposit amounts between \$50 and \$150 and three (3) month's for deposits over \$150, which may be granted at the Company's discretion.

RULES AND REGULATIONS (Continued)

4. Customer Deposits (Continued)

B. Establishment of Credit

In lieu of a deposit, the Company may allow a prospective Customer to satisfactorily establish credit prior to the commencement of service by one of the following methods:

Residential:

- (1) Furnish a satisfactory guarantor to secure payment of bills for the service requested; such guarantor must be a Customer of the Company with a satisfactory payment record. A guarantor's liability shall be terminated when a residential Customer, whose payment of bills is secured by the guarantor, meets the requirements of Section 4C-Refund of Deposit. Guarantors providing security for payment of residential Customer's bills shall only be liable for bills contracted at the service address contained in the contract of guaranty; or
- (2) Furnish an irrevocable letter of credit from a bank equal to two (2) months' average bills; or
- (3) Furnish a surety bond equal to two (2) months' average bills; or
- (4) Pay a cash deposit.

Non-Residential:

- (1) Furnish a satisfactory guarantor to secure payment of bills for the service requested, such a guarantor need not be a Customer of the Company; or
- (2) Furnish an irrevocable letter of credit from a bank equal to two (2) months' average bills; or
- (3) Furnish a surety bond equal to two (2) months' average bills; or
- (4) Pay a cash deposit.

RULES AND REGULATIONS (Continued)

4. Customer Deposits (Continued)

C. Refund of Deposits

After a Customer has established a satisfactory payment record and has had continuous service for a period of 23 months, the utility shall refund the residential Customer's deposits and shall, at its option either refund or pay the higher rate of interest specified below for nonresidential deposits, providing the Customer has not, in the preceding 12 months, (a) made more than one late payment of a bill (after the expiration of 20 days from the date of mailing or delivery by the utility), (b) paid with a check refused by a bank, (c) been disconnected for non-payment, or at any time, (d) tampered with the meter, or (e) used service in a fraudulent or unauthorized manner. Company may, at its option, refund a deposit in less than 23 months.

D. Interest on Deposits

Two percent (2%) per annum interest will be credited to a Consumer's account annually in accordance with the current effective rules and regulations of the Commission. Three percent (3%) per annum will be credited annually on deposits of Residential Consumers qualifying under section (c) above when the company elects not to refund such a deposit after twenty-three (23) months. The Company shall credit annually three percent (3%) per annum on deposits of non-Residential Consumers qualifying for refund under Section (c) until the Commission sets a new interest rate applicable to the Company. No Customer shall be entitled to receive interest on their deposit until and unless a Customer relationship and the deposit have been in existence for a continuous period of six months, then Customer shall be entitled to receive interest for the day of the commencement of the Customer relationship and the placement of deposit. Deposits shall cease to bear interest upon discontinuance of service.

E. New or Additional Deposits

Company may require, upon written notice to an existing Customer of not less than 30 days, a deposit (including guaranty, letter of credit or surety bond) where previously waived or returned, or an additional deposit, in order to secure payment of current bills. Such notice for a deposit shall be separate and apart from any bill for service and shall explain the reason for the deposit; provided, however, that the total amount of the required deposit shall not exceed an amount equal to the average actual charges for service for two billing periods for the 12-month period immediately prior to the date of notice. The thirty (30) day notice shall not apply when service is being reestablished after discontinuance of service for non-payment. In the event the Customer has had service for less than 12 months, then the Company shall base its new or additional deposit upon the average actual monthly billing available.

RULES AND REGULATIONS (Continued)

4. Customer Deposits (Continued)

F. Retention of Deposits

Retention by Company, prior to final settlement, of said deposit shall not be considered as a payment or part payment of any bill for service. Company shall, however, apply said deposit against unpaid bills for service. In such case, Customer shall be required to restore deposit to original amount.

G. Refund of Deposit When Service is Discontinued

Upon discontinuance of service, the deposit and accrued interest shall be credited against the final account and the balance, if any, shall be returned promptly to the Customer, but in no event later than fifteen (15) days after service is discontinued.

5. Customer Facilities

Customer shall make or procure satisfactory conveyance to Company of all necessary easement and rights-of-way, including right of convenient access to Company's property, for furnishing adequate and continuous service or the removal of Company's property upon termination of service.

Customer should furnish Company a description of the load to be connected prior to wiring Customer's premises or purchasing any electric equipment. Company will then furnish Customer such information as characteristics of service which is or will be available at the point of delivery.

All wiring and equipment beyond Company's meter and accessories thereto, necessary to utilize service furnished by Company, shall be installed by and belong to the Customer and be maintained at Customer's expense. Customer shall bring their wiring to a point of connection to Company's service lines at a location satisfactory to Company.

All wiring and electric equipment shall conform to the requirements of the National Electrical Code as adopted by Company and local ordinances, if any.

Company reserves the right to inspect and approve the installation of all wiring and equipment to utilize Company's service; but such inspection or failure to make inspection or the fact that Company may connect to such installation shall not make Company liable for any loss or damage which may be occasioned by the use of such installation or equipment used therefrom or of Company's service.

Customer shall install only such motors or other apparatus or appliances as are suitable for operation with the character of the service supplied by Company, and electric energy must not be used in such a manner as to cause detrimental voltage fluctuations or disturbances in Company's distribution system.

All apparatus used by Customer shall be of such type as to secure the highest practicable commercial efficiency, power factor and proper balancing of phases. Motors which are frequently started or motors arranged for automatic control must be equipped with controlling devices, approved by Company, to give maximum starting torque with minimum current flow.

RULES AND REGULATIONS (Continued)

6. Service Connections

A. General

Company reserves the right to designate the location of the point of connection, transformers and meters and to determine the amount of space which must be left unobstructed for the installation and maintenance thereof. Applicant may request an alternation of such a designation but, if consented to by Company, the excess cost of such revised designation over and above the cost of the original Company design shall be borne by Applicant.

Company reserves the right to postpone to a more favorable season the extension of lines and connection of services during seasons of the year when climatic conditions would cause abnormally high construction costs.

B. Overhead Service in Overhead Zone

Customer's wiring must be brought outside the building wall nearest Company's service wires so as to be readily accessible thereto or to transformer terminals if located close to the wall. All connections between the service entrance and meter location shall comply with local ordinances and shall be in rigid conduit or cable approved by Company. Company will furnish, install and maintain the service conductors to the point of connection to Customer's facilities.

C. Underground Service in Overhead Zone

Customers desiring an underground service in an overhead zone may make application for service with the Company. The Company will install and own the underground service from the meter location to the pole from which connection is to be made, including the necessary run of cable or conduit up the side of the pole. The Customer will pay in advance to the Company the estimated difference in the cost of the underground service and or equivalent overhead service. Underground service will be provided pursuant to F.A.C. 25-6115, Facility Charges for Conversion of Existing Overhead Investor Owned Distribution Facilities.

D. Underground Service in Underground Residential Distribution Systems

The service connection to the building normally will be at the point of the building nearest the point at which the underground system enters the property to be served. If such service connection point on any building is more than seventy-five (75) feet, measured at right angles, from the serving property line, the Customer will pay the difference between an underground service and an equivalent overhead service for all service line in excess of seventy five (75) feet.

RULES AND REGULATIONS (Continued)

E. Underground Service in Underground Zone (Other Than Residential Areas)

Where service is supplied from an underground distribution system, at Company's choice, Company will provide and install the cable conduit or ducts from its manhole or street connection box or main feed lines in street to the property line adjoining the property to be served.

The Customer shall supply and install the cable conduit or ducts from the property line into the building, terminating said conduit or ducts inside the building wall at a point located by the Company inspector. The Customer shall make arrangements with the Company for Company to supply and install continuous run of cable conductors from the manhole or street connection box to the inside of the building wall. Customer shall be charged for materials, labor, and other expenses incurred from the portion of cable installed inside the building.

Where Company is required by governmental or other valid authority to install underground distribution, and abandon overhead distribution, Company shall not be required to bear any of the cost of making the necessary changes on Customer's premises. If, however, Company elects to change an existing Customer's service from overhead to underground, Company shall bear the cost of disconnecting the Customer's service from the overhead system and reconnecting it to the underground system unless such change is necessitated by a change in the Customer's requirements.

7. Line Extensions

A. Overhead Extensions

(1) Free Extensions

- (a) Company shall make extensions to or alterations in its facilities in accordance with Rule 25-6.064 of Florida Public Service Commission, these Rules and Regulations and free of charge to provide service to an applicant or group of applicants located within the Company's service area when the estimated total non-fuel revenue for the first four (4) years from the Applicant or Applicants equals or exceeds the estimated cost of the necessary includable construction; provided, however, that the patronage or demand will be of such permanency as to warrant the expenditure involved.

RULES AND REGULATIONS (Continued)

(b) The formula used to calculate the maximum amount of no-charge extension or alteration will be as follows:

(1) for Customers in rate classes that pay only energy charges, i.e., do not pay demand charges:

$$\text{maximum amount} = 4 \times (\text{non-fuel energy charge KWH}) \\ (\text{estimated annual KWH usage})$$

(2) for Customers in classes that pay both energy charges and demand charges:

$$\text{maximum amount} = 4 \times (\text{non-fuel energy charge KWH}) \\ (\text{estimated annual KWH usage}) \\ + 4 \times (\text{estimated annual demand} \\ \text{charge revenue from sales} \\ \text{over new line})$$

(2) Other Extensions

When the line extension or alteration required in order to furnish service within Company's service area is a reasonable extension of the Company's facilities but greater than the free construction specified above, and the Applicant or Applicants shall contract to use service for at least four (4) years, such extension or alteration shall be made subject to the following condition;

(a) Applicant or Applicants shall make a non-refundable contribution in aid of construction (CIAC)_{OH} prior to commencement of construction, in an amount equal to the amount that the estimated cost to provide the extension or alteration exceeds the maximum amount of the no-charge extension or alteration as determined in A (b) (1) or A (b) (2) above.

B. Underground Extension

(1) New residential subdivisions and multiple-occupancy buildings.

(a) Company shall make underground extension of its facilities to serve new residential subdivisions or new multiple-occupancy buildings, in accordance with the provisions of the "Rules for Residential Electric Underground Service" of the Florida Public Service Commission; provided that the Applicant or Applicants, in accordance with the Rules of the Florida Public Service Commission, will pay to the Company in an amount equal to the difference in cost between an underground system (exclusive of supply system feeders) and an equivalent overhead system.

RULES AND REGULATIONS (Continued)

- (2) Residential, commercial, industrial extensions
- (a) Company shall make underground extensions or alterations in its facilities in accordance with Rule 25-6.115 of Florida Public Service Commission and these Rules and Regulations to provide underground service to an applicant or group of applicants, within the Company's service area provided that the applicant, or group of applicants, pay the Company a contribution in aid of underground construction (CIAC)_{UG} in an amount equal to the estimated difference in cost to provide underground service instead of overhead service to the Applicant(s) plus the amount, if any, by which the estimated cost to provide an overhead service exceeds the maximum amount of no-charge construction (CIAC)_{OH} as determined in A(2) above.
- (b) The following formula shall be used to determine the contribution in aid of underground construction with all cost based on Rule 25-6.115, FAC, Facility Charges for Conversion of Existing Overhead Investor-owned Distribution Facilities :
- (CIAC)_{UG} = (estimated cost to provide underground service facilities including distribution line, transformer, service drop and other necessary fixtures) minus (the estimated cost to provide service using overhead facilities) plus (CIAC)_{OH}.

RULES AND REGULATIONS (Continued)

8. Underground Electric Distribution Facility Charges

A. Definitions

The following words and terms used under this Part shall have the meaning indicated:

- (1) Applicant: The Applicant is the person or entity seeking the undergrounding of existing or newly planned electric distribution facilities by the Company. When a developer requests local government development approval, the local government shall not be deemed the applicant for purposes of this rule.
- (2) Commission: Florida Public Service Commission.
- (3) Cost Estimate: A non-refundable deposit charged an Applicant by the Company for the purpose of preparing a binding cost estimate of the amount required for the Company to construct or convert particular distribution facilities as underground.
- (4) Company: Florida Public Utilities Company.
- (5) Distribution Facilities: All electrical equipment of the Company required to deliver electricity to homes and businesses.
- (6) Facility Charge: That charge required to be paid by an Applicant for the Company to construct or convert particular distribution facilities as underground.
- (7) High Density Subdivision: A subdivision having a density of six (6) or more dwelling units per acre.
- (8) Low Density Subdivision: A subdivision having a density of at least 1.5 dwelling units per acre but less than six (6) dwelling units per acre.
- (9) Overhead: Pertains to distribution facilities consisting of conductors, switches, transformers, etc. which are installed above ground on supporting poles.
- (10) Underground: Pertains to distribution facilities consisting of conductors, switches, transformers, etc. which are installed below or on the ground.

RULES AND REGULATIONS (Continued)

B. General

(1) Application

This tariff section applies to request for underground electric distribution facilities offered in lieu of overhead facilities. The installation of underground distribution lines in new residential subdivisions is not covered in this section of the tariff. These installations are covered under “Rules of the Florida Public Service Commission”, Chapter 25-6115, “Facility Charges for Conversion of Existing Overhead Investor Owned Distribution Facilities”, and the Company’s “Rules and Regulations”, Item 7.

(2) Application Request

An applicant shall submit a request in writing for the Company to develop a cost estimate to accomplish the undergrounding of particular electric facilities. The request shall be accompanied by an appropriate deposit and shall specify the following information:

- a. the area(s) being sought to be undergrounded
- b. a list of all electric Customers affected
- c. an estimated time frame for undergrounding to be accomplished
- d. details of any construction by the Applicant
- e. any other pertinent information which the Applicant possesses that may assist the

RULES AND REGULATIONS (Continued)

C. Cost Estimate Deposits

(1) Non-Binding Cost Estimates

The Company will provide a non-binding cost estimate related to the request at no cost to the Applicant. The non-binding cost estimate shall be an order of magnitude estimate to assist the requestor in determining whether to go forward with a binding cost estimate.

(2) Binding Cost Estimates

Upon the payment of a non-refundable deposit, as specified below, the Company shall provide an applicant with a binding cost estimate specifying the facility charge required for the installation. The facility charge to be collected pursuant to a binding cost estimate from an applicant shall not be subject to increase or refund unless the project scope is enlarged or reduced, or the project is not completed at the request of the applicant.

The deposit shall be forfeited, and the binding cost estimate provided to an Applicant shall be considered expired, if the Applicant does not enter into a contract for the installation of the requested underground electric distribution within 180 days of delivery of the binding cost estimate by the Company. For good cause the Company may extend the 180 day time limit.

The deposit for a binding cost estimate, which approximates the engineering costs for underground facilities associated with preparing the requested estimate, shall be calculated as follows:

I. New Construction (Excluding New Residential Subdivisions)

<u>Facilities Classification</u>	<u>Deposit Amount</u>
Urban Commercial	\$4,540 per overhead primary mile
Urban Residential	\$3,555 per overhead primary mile
Rural Residential	\$3,263 per overhead primary mile

II. Conversions

<u>Facilities Classification</u>	<u>Deposit Amount</u>
Urban Commercial	\$6,815 per overhead primary mile
Urban Residential	\$5,330 per overhead primary mile
Rural Residential	\$4,895 per overhead primary mile
Low Density Subdivision	\$64.00 per lot
High Density Subdivision	\$42.00 per lot

The deposit must be paid to the Company to initiate the estimating process. The deposit will be applied in the calculation of the facility charge to be required for the installation of underground distribution facilities.

RULES AND REGULATIONS (Continued)

D. Construction Contract

(1) General

Upon acceptance by the Applicant of a binding cost estimate, the Applicant shall execute a contract with the Company to perform the construction of the underground distribution facilities. The contract shall specify the type and character of system to be provided; establish the facility charge to be paid by Applicant prior to commencement of construction; specify details of construction to be performed by Applicant, if any; and address those other terms and conditions described below.

(2) Facilities Charge

The charge shall be calculated in accordance with the appropriate formula described below with all costs based on Rule 25-6.115, FAC, Facility Charges for Conversion of Existing Overhead Investor-owned Distribution Facilities:

a. New Construction

Charge =

Estimated cost of construction of underground facilities including underground service laterals to Customers' meters;

Minus, estimated construction cost of overhead facilities including overhead service drops to Customers' meters;

Minus, qualifying cost estimate deposit.

b. Conversion

Charge =

Remaining book value of existing overhead facilities to be removed;

Plus, removal cost of existing overhead facilities;

Minus, salvage value of existing overhead facilities;

Plus, estimated cost of construction of underground facilities including underground service laterals to Customers' meters;

Minus, estimated construction cost of overhead facilities including overhead service drops to Customers' meters;

Minus, qualifying cost estimated deposit.

RULES AND REGULATIONS (Continued)

E. Construction By Applicant

If agreed upon by the Applicant and the Company, the Applicant may construct or install portions of the underground system as long as such work meets the Company's engineering and construction standards. The Company will own and maintain the completed distribution facilities upon accepting the system as operational. The type of system provided will be determined by the Company's standards.

Any facilities provided by the Applicant will be inspected by Company inspectors prior to acceptance. Any deficiencies discovered as a result of these inspections will be corrected by the applicant at his sole expense, including the costs incurred by performing the inspections. Corrections must be made in a timely manner by the Applicant; otherwise the Company will undertake the correction and bill the Applicant for all costs of such correction. These costs shall be additional to the original binding cost estimate.

F. Other Terms And Conditions

- (1) Easements: Easements satisfactory to both the Company and the Customer must be provided for by the Applicant prior to commencement of construction at no expense to the Company. Additional easements are not required when facilities are to be located on private property wholly within an area covered by a recorded subdivision utility easement, namely a reservation and recorded plat of an easement for public utility purposes and where underground electrical facilities are not prohibited. Where underground distribution facilities for serving more than one Customer are located on private property, easements are required.

Secondary voltage underground facilities wholly within one property for the purpose of serving only one Customer do not require easements. All primary voltage underground facilities require easements. Easements are not required for facilities in public rights-of-way.

RULES AND REGULATIONS (Continued)

- (2) Scheduling, Clearing, and Grading: Rights-of-way and easements suitable to the Company must be furnished by the Applicant in a reasonable time to meet service requirements and must be cleared of trees, tree stumps, paving and other obstruction, staked to show property lines and final grade and must be graded to within six (6) inches of final grade by the Applicant before the Company will commence construction, all at no charge to the Company. Such clearing and grading must be maintained by the Applicant during construction by the Company. Grade stakes must be provided at transformer, pull box, and switch locations.
- (3) Restoration: All removal and restoration of buildings, roads, driveways, sidewalks, patios, fences, ditches, landscaping, sprinkler systems, other utilities, etc. shall be the full responsibility of the Applicant and shall cause no cost to the Company. Removal of all construction debris not belonging to the Company shall be the responsibility of the Applicant or other.
- (4) Other Joint Users on the Company Poles: Applicant must make arrangements with all other overhead utilities and third parties to remove their overhead facilities from the Company's poles prior to construction or to concurrently convert their facilities to underground or remove them at no cost to the Company. The Applicant shall produce, if requested by the Company, executed agreements with all joint users guaranteeing this requirement.
- (5) Affected Electric Customers: Applicant must make arrangements with all affected Company Customers to, in a timely fashion, prepare their premises and service entrance for underground electrical service from the new underground distribution system. All Customers affected by the undergrounding request must agree to accept underground service. This Customer conversion will be at no cost to the Company.
- (6) Damage to Company's Underground Facilities: The Applicant shall be responsible to ensure the Company's distribution system, once installed, is not damaged, destroyed, or otherwise disturbed during the construction of the project. This responsibility shall extend not only to those in his employ, but also to his subcontractors, and he shall be responsible for the full cost of repairing such damage.

RULES AND REGULATIONS (Continued)

9. Metering

Company will provide each Customer with a meter or meters for each applicable rate schedule.

Customer, acting jointly with Company, may install, maintain and operate at Customer's expense such check measuring equipment as desired provided that such equipment shall be so installed as not to interfere with operation of Company's equipment and that no electric energy shall be re-metered for resale to another or others.

Before installation and periodically thereafter, each meter shall be tested and adjusted using methods and accuracy limits prescribed or approved by the Florida Public Service Commission. Periodic test and inspection intervals shall not exceed the maximum period allowed by the Florida Public Service Commission.

If upon testing the meter is found to be in error in excess of prescribed accuracy limits, fast or slow, the amount of refund or charge to the Customer shall be determined by methods prescribed or approved by the Florida Public Service Commission.

In the event of stoppage or failure of any meter to register, Customer may be billed for such period on an estimated consumption based upon Customer's use of electric energy in a similar period of like use or on the basis of check meter readings, if available and accurate.

Meters in use shall be tested at the request of Customer and in his presence, if desired, provided only one (1) such test shall be made free of charge within a twelve (12) month period, and provided Customer shall pay the cost of any additional test within this period unless meter is shown to be inaccurate in excess of the tolerances set forth by the Florida Public Service Commission. If the Customer requests a test more frequently, the Company may require a deposit, not to exceed \$50.00, to defray the cost of testing.

10. Billing and Collecting

Each Customer's meter will be read at regular intervals and bills will be rendered on a monthly basis or periodically in accordance with the terms of the applicable rate schedule. Bills will be rendered as soon as practical after determination of their amount and shall be due and payable at the office of Company within twenty (20) days after date of bill. Failure to receive a bill will not entitle Customer to any discount or to the omission of any charge for nonpayment within the time specified.

Partial Month:

Upon commencement of service less than fifteen (15) days prior to a regular monthly read date and when the service continues thereafter to the same Customer at the same address where the Customer is receiving service on monthly rate schedules, no bill will be rendered for service covering such period, but the charge for such period will be included in the bill rendered for the next succeeding monthly billing period.

RULES AND REGULATIONS (Continued)

10. Billing and Collecting (continued)

A separate bill will be rendered for each meter used by Customer unless, for the convenience of Company, multiple meters are used for measurement of the same class of service, in which case a bill will be rendered for the total amount registered by all meters. If Company, (as it may under unusual circumstances), permits more than one Customer to be served through one meter, the minimum bill and the first billing block kilowatt-hours of the applicable rate schedule shall be multiplied by the number of Customer so served and the number of kilowatt-hours in each succeeding block of the rate schedule shall be increased in the same proportion.

Billings in general will be based on meter readings but bills will be adjusted to compensate for errors in meter registration, in the reading thereof, or in the application of meter reading schedules to intervals five (5) days greater or lesser than a month. If the billing period is extended more than five (5) days, the Company will not apply the higher tiered rate if the Customer's higher usage is attributable to the extended billing period.

In case of tampering or unauthorized use, probable consumption will be billed as determined by the maximum quantity of electric energy estimated to have been consumed by the various appliances of Customer and a bill will be rendered for a period encompassing six (6) months prior to the detection of such abuse and /or disconnection for cause.

11. Customer's Liabilities

Company shall have the right to enter the premises of Customer at all reasonable hours for the purpose of making such inspection of Customer's installation as may be necessary for the proper application of Company's rate schedules and Rules and Regulations; for installing, removing, testing, or replacing its apparatus or property; for reading meters; and for the entire removal of Company's property in event of termination of service to Customer for any reason.

All property of Company installed in or upon Customer's premises used and useful in supplying service is placed there under Customer's protection. All reasonable care shall be exercised to prevent loss of or damage to such property and, ordinary wear and tear excepted, Customer will be held liable for any such loss of property or damage thereto and shall pay to Company the cost of necessary repairs or replacements.

No one except employees of Company will be allowed to make any repairs or adjustments to any meter or other piece of apparatus belonging to Company except in case of emergency.

Unauthorized connections to, or tampering with the Company's meters, meter seals, or metering equipment or indications or evidence thereof, subjects the Customer to immediate discontinuance of service, prosecution under the laws of Florida, adjustment of prior bills for services rendered, a tampering penalty of \$500 for residential and non-demand general service customers and \$2,500 for all other customers, and liability for reimbursement to the Company for all extra expenses incurred on this account as a result thereof. The reimbursement for extra expenses incurred as a result of the investigation or as a result thereof shall be the actual amount of such extra expenses and shall be in addition to any charges for service rendered or charges for restoration of service as provided elsewhere in these rules.

RULES AND REGULATIONS (Continued)

11. Customers Liabilities (continued)

Customer shall not materially increase load without first notifying Company and obtaining consent.

Company shall have the right, if necessary, to construct its poles, lines and circuits on Customer's property, and to place its transformers and other apparatus on the property or within the buildings of Customer, at a point or points convenient for such purpose and Customer shall provide suitable space for such installation.

12. Company's Liabilities

Company will use reasonable diligence in furnishing as uniform a supply of electric energy as practicable, except where rate schedules provide otherwise. Company may interrupt its service hereunder, however, for the purpose of making necessary alterations and repairs, but only for such time as may be reasonable or unavoidable, and Company shall give to those Customers it knows may be seriously affected, except in case of emergency, reasonable notice of its intention so to do, and shall endeavor to arrange such interruption so as to inconvenience Customer as little as possible.

Whenever Company deems an emergency warrants interruption or limitation in the service being rendered, such interruption or limitation shall not constitute a breach of contract and shall not render Company liable for damages suffered thereby or excuse Customer from further fulfillment of the contract.

In the event that the supply of electric energy shall be interrupted from causes other than the foregoing or force majeure and such interruption is due to the negligence of Company and Company is liable because thereof, that liability shall be limited to twice the amount which Customer would have paid for electric energy during the period of such interruption. However, Company shall not be liable to Customer for any loss, injury or damage resulting from use of Customer's equipment or from the use of electric service furnished by Company or from the connection of Company's facilities with Customer's wiring and appliances.

RULES AND REGULATIONS (Continued)

13. Force Majeure

Except for payment of bills due, neither the Company nor the Customer shall be liable in damage to the other for any act, omission or circumstances occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, unforeseeable or unusual weather conditions, washouts, arrests and restraint of rules and peoples, civil disturbances, explosions, breakage or accident to machinery or electric lines, temporary failure of electric supply, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause, whether of the kind herein enumerated, or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or any other person or concern not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the party claiming suspension.

14. Discontinuance of Service

The Company reserves the right, but assumes no liability for failure so to do, to discontinue service to any Customer for cause as follows:

A. Without notice,

- (1) if a dangerous condition exists on Customer's premises in wiring or energy-consuming devices.
- (2) because of fraudulent use of the service or tampering with Company's equipment.
- (3) upon request by Customer, subject to any existing agreement between Customer and Company as to unexpired term of service.

B. After five (5) working days' (any day on which the utility's business office is open and the U.S. Mail is delivered) notice in writing,

- (1) for nonpayment of bill for electric service.
- (2) when Company has reasonable evidence that Customer has been previously disconnected for nonpayment at present or other location and is receiving service for his own use under a different name in order to avoid past due payments to Company.

RULES AND REGULATIONS (Continued)

- (3) for refusal or failure to make a deposit or increase a deposit, when requested, to assure payment of bills.
 - (4) for a violation of these Rules and Regulations which Customer refuses or neglects to correct.
- C. Discontinuance of Service When That Service is Medically Essential:

For purposes of this section, a Medically Essential Service Customer is a residential Customer whose electric service is medically essential, as affirmed through the certificate of a medical doctor licensed to practice in the State of Florida. Service is “medically essential” if the Customer has continuously operating electric-powered medical equipment necessary to sustain the life of or avoid serious medical complications requiring immediate hospitalization of the Customer or another permanent resident at the service address. The physician’s certificate shall explain briefly and clearly, in non-medical terms, why continuance of electric service is medically essential, and shall be consistent with the requirements of the Company’s tariff. A Customer who is certified as a Medically Essential Service Customer must renew such certification periodically through the procedures outlined above. The Company may require certification no more frequently than 12 months.

The Company shall provide Medically Essential Service Customers with a limited extension of time, not to exceed thirty (30) days, beyond the date service would normally be subject to disconnection for non-payment of bills (following the requisite notice pursuant to Rule 25-6.105(5) of the Florida Administrative Code). The Company shall provide the Medically Essential Service Customer with written notice specifying the date of disconnection based on the limited extension. The Medically Essential Service Customer shall be responsible for making mutually satisfactory arrangements to ensure payment within this additional extension of time for service provided by the Company and for which payment is past due, or to make other arrangements for meeting medically essential needs.

RULES AND REGULATIONS (Continued)

No later than 12 noon one day prior to the scheduled disconnection of service of a Medically Essential Service Customer, the Company shall attempt to contact such Customer by telephone in order to provide notice of the scheduled disconnect date. If the Medically Essential Service Customer does not have a telephone number listed on the account, or if the utility cannot reach such Customer or other adult resident of the premises by telephone by the specified time, a field representative will be sent to the residence to attempt to contact the Medically Essential Service Customer, no later than 4 PM of the day prior to scheduled disconnection. If contact is not made, however, the company may leave written notification at the residence advising the Medically Essential Service Customer of the scheduled disconnect date; thereafter, the Company may disconnect service on the specified date. The Company will grant special consideration to a Medically Essential Service Customer in the application of Rule 26-6.097(3) of the Florida Administrative Code.

In the event that a Customer is certified as a Medically Essential Customer, the Customer shall remain solely responsible for any backup equipment and/or power supply and a planned course of action in the event of a power outage. The Company does not assume, and expressly disclaims, any obligation or duty; to monitor the health or condition of the person requiring medically essential service; to insure continuous service; to call, contact, or otherwise advise of service interruptions; or, except expressly provided by this section, to take any other action (or refrain from any action) that differs from the normal operation of the Company.

15. Reconnection of Service

When service shall have been discontinued for any of the reasons set forth in these Rules and Regulations, Company shall not be required to restore service until the following conditions have been met by the Customer:

- A. Where service was discontinued without notice,
- (1) The dangerous condition shall be removed and, if the Customer had been warned of the condition a reasonable time before the discontinuance and had failed to remove the dangerous condition, a reconnection fee shall be paid.
 - (2) all bills for service due Company by reason of fraudulent use or tampering shall be paid, a deposit to guarantee the payment of future bills shall be made, and a reconnection fee shall be paid.
 - (3) if reconnection is requested on the same premises after discontinuance, a reconnection fee shall be paid.

RULES AND REGULATIONS (Continued)

- B. Where service was discontinued with notice,
- (1) satisfactory arrangements for payment of all bills for service then due shall be made and a reconnection fee shall be paid.
 - (2) a satisfactory arrangement for the payment of bills then due under a different name shall be made and a reconnection fee shall be paid.
 - (3) a satisfactory guarantee of payment for all future bills shall be furnished and a reconnection fee shall be paid.
 - (4) the violation of these Rules and Regulations shall be corrected and a reconnection fee shall be paid.

The reconnection fee as required under items A and B above shall be as follows:

During Normal Business Hours	\$ 70.00
After Normal Business Hours	\$325.00

16. Termination of Service

Subject to any existing agreement between Customer and Company, if Customer wishes the electric service to be terminated, he shall give notice to the Company at least three (3) days prior to the time that such termination shall become effective. Customer will be held liable both for any electric energy that may pass through the meter and safe custody of the Company's property until three (3) days after such notice shall have been given, provided that the meter and/or other movable equipment shall not have been removed within that time by the Company.

If Customer wishes Company's property to be removed, he shall give notice to the Company at least ten (10) days prior to the time that such removal must be made.

RULES AND REGULATIONS (Continued)

17. Limitations of Supply

Company reserves the right, subject to regulatory authority having jurisdiction, to limit, restrict or refuse service that will result in additions to its distribution system and/or production capacity and/or alterations in its contractual requirements of supply from non-affiliated companies that may jeopardize service to existing Customers.

18. Temporary Service

The Company upon request will supply temporary service when the Company's distribution system is near the requested location.

When the temporary service is to be replaced later with a permanent service, the Company will install a service drop, meter and other facilities as may be necessary to the Customer's temporary service pole and remove same at the termination of temporary service. To recover the cost of installing and removing such temporary service, an advance of \$415.00 per service to the applicant will be applied. For underground temporary service using Customer provided wire, an advance of \$250.00 per service will be required. Should the Company be required to install an additional pole, additional charges will apply. A pole with an overhead service will be an additional \$835.00, and a pole with an underground service will be an additional \$1,000.00.

When the temporary service will not be replaced by a permanent service or when the location is such that multiple temporary poles and/or extensive facilities are required, the Company will estimate the cost of installing and removing the temporary facilities and the advance charge to the applicant will be that cost estimate.

The rate schedule for temporary service shall be that which is applicable to the class of service for that Customer.

19. Fees for Initial Connections

In addition to the deposit or suitable guarantee to cover the payment of bills as required by the Rules and Regulations, each Applicant or Customer shall pay an initial turn-on connection fee of \$125.00.

20. Re-establish or Make Change to Account

There shall be a charge to re-establish or change any account to which service is currently rendered under any of the Company's rate schedules in the amount of \$45.00. Should it be necessary, at the Customer's request, to disconnect and then reconnect the service to the account, the Customer shall pay a temporary disconnect then reconnect fee in the amount of \$81.00.

RULES AND REGULATIONS (Continued)

21. Returned Check Charge

The service charge for each worthless check shall be determined in accordance with Section 68.065, Florida Statutes. As of October 1, 1996, Section 68.065, F.S., provided for a service charge of \$25.00, if the face value does not exceed \$50.00, \$30.00, if the face value exceeds \$50.00 but does not exceed \$300.00 and \$40.00, or 5 percent of the face amount of the check, whichever is greater if the face value exceeds \$300.00. Such service charge shall be added to the Customer's bill for electric service for each check dishonored by the bank upon which it is drawn. Termination of service shall not be made for failure to pay the returned check charge.

22. Late Payment Charge

A bill shall be considered past due upon expiration of twenty (20) days from the date of mailing or other delivery thereof by the Company. The balance of all past due charges for services rendered are subject to a Late Payment charge of 1.5% or \$5.00, whichever is greater, except the accounts of federal, state, and local governmental entities, agencies, and instrumentalities. A Late Payment Charge shall be applied to the accounts of federal, state, and local governmental entities, agencies and instrumentalities at a rate no greater than allowed, and in a manner permitted by applicable law.

23. Measuring Customer Service

- A. All energy sold to Customers, except that sold under flat rate schedule, shall be measured by commercially acceptable measuring devices owned and maintained by the Company, except where it is impractical to meter loads, such as street lighting, temporary or special installations, in which case the consumption may be calculated, or billed on demand or connected load rate or as provided in Company's filed tariff.
- B. When there is more than one meter at a location the metering equipment shall be so tagged or plainly marked as to indicate the circuit metered. Where similar types of meters record different quantities, (kilowatt hours and relative power, for example), metering equipment shall be tagged or plainly marked to indicate what the meters are recording.
- C. Meters which are not direct reading shall have the multiplier plainly marked on the meter. All charts taken from recording meters shall be marked with the date of the record, the meter number, Customer, and chart multiplier. The register ratio shall be marked on all meter registers. The watt-hour constant for the meter itself shall be placed on all watt-hour meters.
- D. Metering equipment shall not be set "fast" or "slow" to compensate for supply transformer or line losses.
- E. Individual electric metering by Company shall be required for each separate occupancy unit of new commercial establishments, residential buildings, condominiums, cooperatives, marinas, and trailer, mobile home and recreational vehicle parks for which construction is commenced after January 1, 1981. Individual electric meters shall not, however, be required:

RULES AND REGULATIONS (Continued)

1. In those portions of a commercial establishment where the floor space dimensions or physical configuration of the units are subject to alteration, as evidenced by non-structural element partition walls, unless the utility determines that adequate provisions can be made to modify the metering to accurately reflect such alterations;
2. For electricity used in central heating, ventilating and air conditioning systems, or electric back up service to storage heating and cooling systems;
3. For electricity used in specialized-use housing accommodations such as hospitals, nursing homes, living in facilities located on the same premises as, and operated in conjunction with, a nursing home or other health care facility providing at least the same level and types of services as a nursing home, convalescent homes, facilities certified under chapter 651, Florida Statutes, college dormitories, convents, sorority houses, fraternity houses, motels, hotels, and similar facilities.
4. For separate, specially designated areas for overnight occupancy at trailer, mobile home and recreational vehicle parks where permanent residency is not established and for marinas where living aboard is prohibited by ordinance, deed restriction, or other permanent means.
5. For new and existing time-share plans, provided that all of the occupancy units which are served by the master meter or meters are committed to a timeshare plan as defined in Section 721, Florida Statutes, and none of the occupancy units are used for permanent occupancy. When a time-share plan is converted from individual metering to master metering, the Customer must reimburse the utility for the costs incurred by the utility for the conversion. These costs shall include, but not be limited to, the undepreciated cost of any existing distribution equipment which is removed or transferred to the ownership of the Customer, plus the cost of removal or relocation of any distribution equipment, less the salvage value of any removed equipment.

For purpose of this rule:

1. "Occupancy unit" means that portion of any commercial establishment, single and multi-unit residential building, or trailer, mobile home or recreational vehicle park, or marina which is set apart from the rest of such facility by clearly determinable boundaries as described in the rental, lease, or ownership agreement for such unit.

"Time-sharing plan" means any arrangement, plan, scheme or similar device, whether by membership, agreement, tenancy in common, sale, lease, deed, rental agreement, license, or right-to-use agreement or by any other means, whereby a purchaser, in exchange for a consideration, receives a right to use accommodations or facilities, or both, for a specific period of times less than a full year during any given year, but not necessarily for consecutive years, and which extends for a period of more than three years.

RULES AND REGULATIONS (Continued)

3. The construction of a new commercial establishment, residential building, marina, or trailer, mobile home or recreational vehicle park shall be deemed to commence on the date when the building structure permit is issued.
 4. The individual metering requirement is waived for any time sharing facility for which construction was commenced before December 23, 1982, in which separate occupancy units were not metered in accordance with subsection (5) (a).
 5. "Overnight Occupancy" means use of an occupancy unit for a short term such as per day or per week where permanent residency is not established.
 6. The term "cost" as used herein means only those charges specifically authorized by the electric utility's tariff, including but not limited to the Customer, energy, demand, fuel, and conservation charges made by the Company plus applicable taxes and fees to Customer of record responsible for the master meter payments. The term does not include late payment charges, returned check charges, the cost of distribution system behind the master meter, the cost of billing, and other such costs.
- F. Where individual metering is not required under Subsection (E) and master metering is used in lieu thereof, reasonable apportionment methods, including sub-metering, may be used by Customer of record or the owner of such facility solely for the purpose of allocating the cost of the electricity billed by the Company.
- G. Any fees or charges allocated by Customer of record for electricity billed to Customer's account by Company, whether based on the use of sub-metering or any other allocation method, shall be determined in a manner which reimburses the Customer of record for no more than the Customer's actual cost of electricity.

RULES AND REGULATIONS (Continued)

24. Miscellaneous Service Charges

A. Initial establishment of service	\$ 125.00
B. Re-establish or Change Account	\$ 45.00
C. Temporary disconnect then reconnect Service	\$ 81.00
D. Re-connect service after being disconnected for rule violation	
Normal Business Hours	\$ 70.00
After Normal Business Hours	\$325.00
E. Connect and then disconnect temporary Service	\$ 135.00
F. Collection Charge	\$ 50.00

INDEX OF RATE SCHEDULES

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*RATE SCHEDULE RS
RESIDENTIAL SERVICE*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable for service to a single family dwelling unit occupied by one family or household and for energy used in commonly-owned facilities in condominium and cooperative apartment buildings.

Character of Service

Single-phase service at nominal secondary voltage of 115/230 volts; three-phase service if available.

Limitations of Service

The maximum size of any individual single-phase motor hereunder shall not exceed five (5) horsepower.

The Company shall not be required to construct any additional facilities for the purpose of supplying three-phase service unless the revenue to be derived therefrom shall be sufficient to yield the Company a fair return on the value of such additional facilities.

Monthly Rate

Customer Facilities Charge:

\$24.40 per Customer per month

Base Energy Charge:

3.042¢/KWH for usage up to 1000 KWH's/month

4.983¢/KWH for usage above 1000 KWH's/month

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

*RATE SCHEDULE RS
RESIDENTIAL SERVICE*

Purchased Power Costs

See Sheet Nos. 7.021 & 7.022.

Conservation Costs

See Sheet Nos. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Budget Billing Program (optional)

An electing Customer's participation in the budgeted payment plan will be continuous unless the Customer requests that participation in the plan be terminated or that Electric Service be terminated, or the Customer is delinquent in paying the budgeted payment amount and becomes subject to the collection action on the service account. At that time, the Customer's participation in the program will be terminated and the Customer shall settle their account with the Company in full. If a Customer requests to terminate participation in the program, but remains a Customer of the Company, the Customer shall pay any deferred debit balance with their next regular monthly bill, and any deferred credit balance shall be used to reduce the amount due for the next regular monthly bill. An electing Customer may request that participation be terminated at any time, but once terminated by Customer request or due to collection action, will be limited to a six (6) month waiting period before Customer may rejoin the Budget Billing Program.

Terms and Conditions

Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.

RESERVED FOR FUTURE USE

*RATE SCHEDULE GS
GENERAL SERVICE – NON DEMAND*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties
And on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial lighting, heating, cooking and small power loads aggregating
25 KW or less.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point.

Monthly Rate

Customer Facilities Charge:

\$40.00 per Customer per month

Base Energy Charge:

All KWH 4.668¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in
January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

*RATE SCHEDULE GS
GENERAL SERVICE – NON-DEMAND*

Purchased Power Costs

See Sheet Nos. 7.021 & 7.022.

Conservation Costs

See Sheet No. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Terms and Conditions

Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.

*RATE SCHEDULE GSD
GENERAL SERVICE – DEMAND*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 25 KW but less than 500 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 25 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Single or three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:
\$126.44 per Customer per month

Demand Charge:
Each KW of Billing Demand \$6.89/KW

Base Energy Charge
All KWH 0.840¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet Nos. 7.021 & 7.022.

*RATE SCHEDULE GSD
GENERAL SERVICE - DEMAND*

Conservation Costs

See Sheet Nos. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Billing Demand

The billing demand in any month shall be the greatest of the following:

- (a) The highest fifteen-minute average load for the current month, as registered by a demand meter or indicator.
- (b) The highest fifteen-minute average load for the current month after adjustment for power factor, in accordance with the Power Factor Clause of this schedule.
- (c) For those Customers electing to take service under this rate schedule in lieu of the otherwise applicable rate schedule the billing demand shall be as in either (a) or (b) above, but not less than 20 KW.

Terms of Service

Not less than one year.

Power Factor of Clause

The Company reserves the right to measure power factor and if it is less than 90%, adjust the maximum demand for any month by multiplying the measured demand by 90% and dividing by the actual power factor.

Transformer Ownership Discount

If the customer elects to take service at the available primary voltage and furnish and maintain any transformers required, the monthly demand charge will be reduced by fifty five (55) cents per kilowatt. Such customers will be metered at primary voltage and in recognition of estimated average transformation losses of 1% the KW and KWH measured units shall be multiplied by a factor of 0.99 for billing purposes.

Terms and Conditions

Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.

*RATE SCHEDULE GSLD
GENERAL SERVICE-LARGE DEMAND*

Availability

Available within the territory served by the Company in Jackson, Calhoun and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial, industrial and municipal service with a measured demand of 500 KW but less than 5000 KW for three or more months out of the twelve consecutive months ending with the current billing period. Also available, at the option of the Customer, to any Customer with demands of less than 500 KW who agrees to pay for service under this rate schedule for a minimum initial term of twelve months.

Character of Service

Three-phase service at available standard voltage.

Limitations of Service

Service shall be at a single metering point at one voltage.

Monthly Rate

Customer Facilities Charge:	
\$241.70 per Customer per month	
Demand Charge:	
Each KW of Billing Demand	\$9.86/KW
Base Energy Charge	
All KWH	0.390¢/KWH

Purchased Power Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January.

Minimum Bill

The minimum monthly bill shall consist of the above Customer Facilities Charge plus the Demand Charge for the currently effective billing demand.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet No. 7.021 & 7.022.

*RATE SCHEDULE GSLD
GENERAL SERVICE-LARGE DEMAND*

Conservation Costs

See Sheet Nos. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Billing Demand

The billing demand in any month shall be the greatest of the following:

- (d) The highest fifteen-minute average load for the current month, as registered by a demand meter or indicator.
- (e) The highest fifteen-minute average load for the current month after adjustment for power factor, in accordance with the Power Factor Clause of this schedule.
- (f) For those Customers electing to take service under this rate schedule in lieu of the otherwise applicable rate schedule the billing demand shall be as in either (a) or (b) above, but not less than 400 KW.

Terms of Service

Not less than one year.

Power Factor of Clause

The Company reserves the right to measure power factor and if it is less than 90%, adjust the maximum demand for any month by multiplying the measured demand by 90% and dividing by the actual power factor.

Transformer Ownership Discount

If the customer elects to take service at the available primary voltage and furnish and maintain any transformers required, the monthly demand charge will be reduced by fifty five (55) cents per kilowatt. Such customers will be metered at primary voltage and in recognition of estimated average transformation losses of 1% the KW and KWH measured units shall be multiplied by a factor of 0.99 for billing purposes.

Terms and Conditions

Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.

RATE SCHEDULE GSLD 1
GENERAL SERVICE - LARGE DEMAND 1

Availability

Available within the territory served by the Company in Jackson, Calhoun, and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to commercial and industrial services of Customers contracting for at least 5,000 kilowatts of electric service.

Character of Service

Three-phase, 60 hertz, electric service delivered and metered at a single point at the available transmission voltage, nominally 69,000 volts or higher.

Monthly Base Rates

Customer Facilities Charge:	\$1,183.57
Base Transmission Demand Charge:	\$2.74/KW of Maximum/NCP Billing Demand
Excess Reactive Demand Charge:	\$0.53 kVar of Excess Reactive Demand

Purchased Power Charges

Purchased power charges are adjusted by the FPSC annually. Current purchased power rates are listed on Sheet Nos. 7.021 and 7.022. The Purchased Power Charges recover Energy and Demand Charges billed to FPUC by FPUC's Wholesale Energy Provider and Wholesale Cogeneration Provider including applicable line losses and taxes. See Sheet Nos. 7.010 and 7.011 for the methodology used to determine purchased power rate and calculation to develop annual true-up calculations.

Minimum Bill

The minimum monthly bill is the sum of the Transmission Demand Charge and the Customer Charge plus any Purchased Power Charges attributed to Transmission Demand Fuel Charge.

Terms of Payment

Bills are rendered net and due and payable within twenty (20) days from date of bill.

Conservation Costs

Not applicable.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

RATE SCHEDULE GSLD 1
GENERAL SERVICE-LARGE DEMAND 1

Coincident Peak (CP) Billing Demand

The CP Billing Demand in any month shall be the Customer's greatest one hour average load as registered by FPUC's demand meter coincident with the FPUC System Peak or the Wholesale Energy Providers System Peak for the purposes as described below:

- 1) FPUC System Peak for the purpose of determining the Generation Demand Fuel Charge. The demand may be adjusted to correct to 90% power factor based on billing from Wholesale Energy Provider.
- 2) FPUC System Peak for the purpose of determining the Excess Reactive Demand Charge.
- 3) Wholesale Energy Providers System Peak for the purpose of determining the Transmission Demand Charge. The demand may be adjusted to correct to 95% power factor based on billing from Wholesale Energy Provider.

Maximum Demand (Non-Coincident Peak (NCP) Billing Demand)

The Maximum Demand (NCP Billing Demand) (Transmission Demand Charge) in any month shall be the Customer's greatest one hour average load as registered by FPUC's demand meter, but not less than 5,000 KW. This will be used as the purchased power value for billing purposed during the year and will be trued-up annually.

Excess Reactive Demand

The Excess Reactive Demand in any month shall be any lagging kVar in excess of one-half of the CP Billing Demand in that month. For the purpose of determining the Excess Reactive Demand charge, the CP Billing Demand will be coincident with the FPUC System Peak.

Coincident Peak (CP) Generation Demand Fuel Charge (Purchased Power Charge)

The Generation Demand Fuel Charge recovers the Wholesale Energy Providers Demand Charge for Generation Services billed to FPUC including system line losses and applicable taxes. The charge is applied to the Customer's CP Billing Demand coincident with the FPUC System Peak.

Transmission Contract Demand Fuel Charge (Purchased Power Charge)

The Transmission Demand Fuel Charge recovers the Wholesale Energy Providers Demand Charge for Transmission Services billed to FPUC including system line losses and applicable taxes. The charge is applied to the Customer's CP Billing Demand or cogeneration output coincident with the Wholesale Providers system Peak, whichever is higher.

Energy Charge (Purchased Power Charge)

The Energy Charge recovers the Energy Charge from the Wholesale Energy Provider and Wholesale Cogeneration Energy Provider including system line losses and applicable taxes.

Term of Service

Contract for service hereunder shall be for a period of not less than one year.

Terms and Conditions

Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.

RESERVED FOR FUTURE USE

*RATE SCHEDULE LS
 LIGHTING SERVICE*

Availability

Available within the territory served by the Company in Calhoun, Jackson and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to any Customer for non-metered outdoor lighting service.

Character of Service

Lighting service from dusk to dawn as described herein.

Limitations of Service

Service is limited to lighting by high-pressure sodium vapor, metal halide, or light emitting diode lamps mounted on Company-owned poles as described herein. Company-owned facilities will be installed only on Company-owned poles.

Monthly Rate

When lighting fixtures are mounted on existing poles and served directly from existing overhead secondary distribution lines:

Type Facility	Lamp Lumens	Size Watts	KWH/Mo. Estimate	Facilities Charge	Maintenance* Charge	Energy Charge	Total Charge
High Pressure Sodium Lights (CLOSED TO NEW CUSTOMERS)							
Acorn	16,000	150	61	\$23.91	\$3.02	\$3.87	\$30.80
ALN 440	16,000	150	61	\$34.08	\$4.03	\$3.87	\$41.98
Amer. Rev.	9,500	100	41	\$11.73	\$3.99	\$2.61	\$18.33
Amer. Rev.	16,000	150	61	\$10.99	\$4.04	\$3.87	\$18.90
Cobra Head	9,500	100	41	\$8.80	\$2.56	\$2.61	\$13.97
Cobra Head	22,000	200	81	\$11.87	\$3.07	\$5.17	\$20.11
Cobra Head	28,500	250	101	\$14.12	\$4.04	\$6.44	\$24.60
Cobra Head	50,000	400	162	\$13.19	\$3.36	\$10.37	\$26.92
Flood	28,500	250	101	\$13.81	\$2.94	\$6.44	\$23.19
Flood	50,000	400	162	\$21.67	\$2.76	\$10.37	\$34.80
Flood	130,000	1,000	405	\$27.15	\$3.64	\$25.86	\$56.65
SP2 Spectra	9,500	100	41	\$30.12	\$3.76	\$2.61	\$36.49
Metal Halide Lights (CLOSED TO NEW CUSTOMERS)							
ALN 440	16,000	175	71	\$32.61	\$3.17	\$4.58	\$40.36
Flood	50,000	400	162	\$14.72	\$2.68	\$10.37	\$27.77
Flood	130,000	1,000	405	\$25.02	\$3.55	\$25.86	\$54.43
Shoebox	16,000	175	71	\$27.54	\$3.56	\$4.58	\$35.68
Shoebox	28,500	250	101	\$29.31	\$3.98	\$6.44	\$39.73
SP2 Spectra	9,500	100	41	\$29.89	\$3.64	\$2.61	\$36.14
Vertical Shoebox	130,000	1,000	405	\$30.90	\$4.03	\$25.86	\$60.79

*RATE SCHEDULE LS
 LIGHTING SERVICE*

Light Emitting Diode Lights

Type	Facility Type	Lamp Lumens	Size Watts	Est. KWH/Mo.	Charges			
					Facilities	Maintenance	Energy	Total
50W Outdoor Light (100W Equivalent)		5,682	50	17	\$7.99	\$2.53	\$1.08	\$11.60
50W Cobra Head (100W Equivalent)		5,944	50	17	\$10.09	\$3.14	\$1.08	\$14.31
82W Cobra Head (200W Equivalent)		9,600	82	28	\$9.45	\$2.95	\$1.78	\$14.18
130W Cobra Head (250W Equivalent)		14,571	130	45	\$9.41	\$2.94	\$2.87	\$15.22
210W Cobra Head (400W Equivalent)		28,653	210	72	\$16.45	\$4.80	\$4.59	\$25.84
26W American Revolution Decorative (100W Equivalent)		2,650	26	9	\$9.45	\$3.30	\$0.57	\$13.32
44W American Revolution Decorative (150W Equivalent)		4,460	44	15	\$9.36	\$3.27	\$0.96	\$13.59
90W Acorn Decorative (150W Equivalent)		10,157	90	31	\$13.53	\$4.50	\$1.98	\$20.01
60W Post Top Decorative (150W Equivalent)		7,026	60	21	\$23.97	\$7.59	\$1.34	\$32.90
80W Flood (250W Equivalent)		12,500	80	27	\$13.11	\$4.13	\$1.72	\$18.96
170W Flood (400W Equivalent)		24,000	170	58	\$13.11	\$4.13	\$3.70	\$20.94
150W Flood (350W Equivalent)		20,686	150	52	\$13.11	\$4.13	\$3.31	\$20.55
290 W Flood (1,000W Equivalent)		38,500	290	100	\$13.11	\$4.13	\$6.37	\$23.61
82W Shoe Box (175W Equivalent)		20,500	23	276	\$11.56	\$3.92	\$3.31	\$18.79
131W Shoe Box (250W Equivalent)		17,144	131	45	\$13.02	\$4.36	\$2.87	\$20.25

Charges for other Company-owned facilities:

1)	30' Wood Pole	\$5.85
2)	40' Wood Pole Std	\$13.02
3)	18' Fiberglass Round	\$12.12
4)	13' Decorative Concrete	\$17.17
5)	20' Decorative Concrete	\$19.92
6)	35' Concrete Square	\$19.22
7)	10' Deco Base Aluminum	\$22.53
8)	30' Wood Pole Std	\$6.51

For the poles shown above that are served from an underground system, the Company will provide up to one hundred (100) feet of conductor to service each fixture. The Customer will provide and install the necessary conduit system to Company specifications.

Purchased Power Charges

Purchased power charges are adjusted annually by the Florida Public Service Commission. For current purchased power costs included in the tariff, see Sheet No. 7.021 & 7.022.

Minimum Bill

The above rates times the number of lamps connected.

*RATE SCHEDULE LS
LIGHTING SERVICE*

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

Purchased Power Costs

See Sheet No. 7.021 & 7.022.

Conservation Costs

See Sheet No. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Term of Service

Service under this rate schedule shall be by written contract for a period of five or more years.

Terms and Conditions

1. Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.
2. The charges set forth above cover the initial installation of overhead lines, poles and fixture assembly including bracket, and the maintenance duty as limited to lamp renewals due to burn outs only, or the repair or replacement of equipment causing lamps not to be illuminated.

The Company will repair or replace malfunctioning lighting fixtures maintained by the company in accordance with Section 768.1382, Florida Statutes (2005). Maintenance duty to be undertaken by Florida Public Utilities Company is limited to lamp renewal due to burn outs only, or the repair or replacement of equipment causing lamps not to be illuminated. Such burnt out lamp replacements or repairs causing non-illumination of lamps will be performed only during regular daytime working hours as soon as practical after notification of the burn out or non-illumination conditions of the lamp by the Customer. The maintenance duties undertaken herein are expressly limited to our paying Customer and are not to be deemed to create a duty to the general public at large.

*RATE SCHEDULE OSL
MERCURY VAPOR LIGHTING SERVICE
(Closed To New Installations)*

Availability

Available within the territory served by the Company in Calhoun, Jackson and Liberty Counties and on Amelia Island in Nassau County.

Applicability

Applicable to any Customer for mercury vapor lighting service.

Character of Service

Lighting service from dusk to dawn as described herein.

Limitations of Service

Service is limited to lighting by mercury vapor lamps of 7,000 or 20,000 initial level of lumens mounted on wood poles, as described herein.

Monthly Rate

When lighting fixtures are mounted on existing poles and served directly from existing overhead secondary distribution lines:

<u>Lamp Size Lumens</u>	<u>KWH/Mo. Estimate</u>	<u>Facilities Charge</u>	<u>Maintenance* Charge</u>	<u>Energy Charge</u>	<u>Total Charge</u>
7,000	72	\$1.69	\$1.51	\$4.49	\$7.69
20,000	154	\$1.86	\$1.60	\$9.65	\$13.11

For concrete or fiberglass poles and/or underground conductors, etcetera, the Customer shall pay a lump sum amount equal to the estimated differential cost between the special system and the equivalent overhead-wood pole system.

Purchased Power

Charges

Purchased power charges are adjusted by the Florida Public Service Commission, normally each year in January. For current purchased power costs included in the tariff, see Sheet Nos. 7.021 & 7.022.

Minimum Bill

The above rates times the number of lamps connected.

Terms of Payment

Bills are rendered net and are due and payable within twenty (20) days from date of bill.

*RATE SCHEDULE OSL
MERCURY VAPOR LIGHTING SERVICE
(Closed To New Installations)*

Purchased Power Costs

See Sheet No. 7.021 & 7.022.

Conservation Costs

See Sheet No. 7.021 & 7.022.

Franchise Fee Adjustment

Customers taking service within franchise areas shall pay a franchise fee adjustment in the form of a percentage to be added to their bills prior to the application of any appropriate taxes. This percentage shall reflect the Customer's pro rata share of the amount the Company is required to pay under the franchise agreement with the specific governmental body in which the Customer is located.

Terms of Service

Service under this rate schedule shall be by written contract for a period of two or more years.

Terms and Conditions

1. Service under this rate schedule is subject to the Company's Rules and Regulations applicable to electric service.
 2. The charges set forth above cover the initial installation of overhead lines, poles and fixture assembly including bracket, and maintenance duty as limited including lamp renewals due to burn outs only, or the repair or replacement of equipment causing lamps not to be illuminated. Such burnt out lamp replacements or repairs causing non-illumination of lamps will be performed as soon as practical after notification of the burnt out lamp or non-illumination by patrols made by company personnel or the Customer. However, Company shall not be required to replace existing street lighting fixtures for Customers receiving service under this rate.
- * The Company will repair or replace malfunctioning lighting fixtures maintained by the company in accordance with Section 768.1382, Florida Statutes (2005). Maintenance duty to be undertaken by Florida Public Utilities Company is limited to lamp renewal due to burn outs only, or the repair or replacement of equipment causing lamps not to be illuminated. Such burnt out lamp replacements or repairs causing non-illumination of lamps will be performed during regular daytime working hours as soon as practical after notification of the burn out or non-illumination conditions of the lamp by the Customer. The maintenance duties undertaken herein are expressly limited to our paying Customer and are not to be deemed to create a duty to the general public at large.

ECONOMIC DEVELOPMENT RIDER PROGRAM-EDRP

Availability:

This Economic Development Rate Program (the "Program") is available throughout the entire territory served by Florida Public Utilities Company. The Qualifying load and employment requirements under this Rider must be achieved at the same delivery point. Additional metering equipment may be required for service under this Rider.

Application:

This Program is applicable to new electric load associated with:

- (1) Initial permanent service to new commercial and industrial establishments.
- (2) Commercial or industrial space that has been vacant for more than six months prior to the application for service under the Program. Verification of vacancy will be established by evidence of no or minimal electric load during the time period in question.
- (3) The expansion of existing establishments. For existing establishments, new load is the net incremental load above that which existed prior to approval for service under this Program.

The new load applicable under this Program for new and vacant establishments must be a minimum of 200 kW at a single delivery point. In the case of the expansion of existing facilities, the added new load must be a minimum of 100 kW, however, in order to qualify, the total load after the addition of the new load must be a minimum of 200 kW at a single delivery point. To qualify for service under this Program, the Customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added.

In order to take service under the Program, the Customer must provide sufficient evidence to Florida Public Utilities Company to establish that the availability of the Program is a significant factor in the Customer's location or expansion decision.

Initial application for this Program is not available to existing load. However, if a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits outlined below.

This Program is not available for load shifted from one establishment or delivery point on the Florida Public Utilities system to another on the Florida Public Utilities system.

ECONOMIC DEVELOPMENT RIDER PROGRAM-EDRP (Continuea)

Monthly Rate:

The rates and all other terms and conditions of the Customer's otherwise applicable rate schedule shall be applicable under this Program. A credit based on the percentages below will be applied to the demand charges and non-fuel (base) energy charges of the Customer's otherwise applicable rate schedule associated with the Customer's new load:

Year 1 - 20% reduction
Year 2 - 15% reduction
Year 3 - 10% reduction
Year 4 - 5% reduction
Year 5 - 0% reduction

The above credit will be deducted from the monthly electric bill as computed in accordance with the provisions of the Monthly Rate section of the Customer's applicable rate schedule before application of any discounts or adjustments. All other charges including the Customer charge and energy conservation charge will be based on the Customer's otherwise applicable rate. The otherwise applicable rates may be any of the following: GSD, GSLD, or GSLD1.

Term of service:

The Customer agrees to a five-year contract term. Service under this Program will terminate at the end of the fifth year. Florida Public Utilities Company may terminate service under this Program at any time if the Customer fails to comply with the terms and conditions of this Program. Failure to: 1) maintain the level of employment specified in the Customer's Service Agreement and/or 2) purchase from Florida Public Utilities the amount of load specified in the Customer's Service Agreement will be considered grounds for termination.

If Florida Public Utilities Company terminates service under the Program for the Customer's failure to comply with its provisions, or if the Customer opts to terminate service under the Program, the Customer will be placed on their applicable rate schedule with no future discounts or rate reductions.

Service under this Rider is subject to the Rules and Regulations of the Company and the Florida
Public Service Commission.

ECONOMIC DEVELOPMENT RIDE PROGRAM-EDRP

ECONOMIC DEVELOPMENT RIDER PROGRAM- EDRP

Service Agreement

The Customer is applying for service under the Economic Development Rate Program based upon new or expanded load as indicated below (Check one):

- New Load associated with a new commercial or industrial establishment
- New Load established in commercial or industrial space that has been vacant for more than six months
- Expanded Load associated with an existing establishment

CUSTOMER NAME _____

SERVICE ADDRESS _____

TYPE OF BUSINESS _____

The Customer hereto agrees as follows:

1. For new and vacant establishments, a minimum of 200 kW of measured demand must be added at a single delivery point.
2. For existing establishments that are expanding, a minimum of 100 kW of measured demand must be added at a single delivery point, and the total measured demand after the addition of the new load must be a minimum of 200 kW.
3. In all cases, the Customer must employ an additional work force of at least 10 full-time employees at the delivery point to which the load is added.
4. That the quantity of new or expanded load shall be 200KW of Demand.
5. The nature of this new or expanded load is _____
6. That in the case of a new Customer adding load to vacant facilities, the commercial/industrial space associated with the new load has been vacant for more than six months.
7. In case of early termination, the Customer shall repay Florida Public Utilities all of the credits provided under the Program to date.
8. To initiate service under this Program on _____, _____ and terminate service under this Program on _____, _____. This shall constitute a period of five years.
9. To provide verification that the availability for this Program is a significant factor in the Customer's location/expansion decision.
10. If a change in ownership occurs after the Customer contracts for service under this Program, the successor Customer may be allowed to fulfill the balance of the contract under the Program and continue the schedule of credits.
11. That in the case of new load established in a vacant facility to provide verification that there is no affiliation with any prior occupant.

Signed: _____
Title: _____
Date: _____

Accepted by: Florida Public Utilities Company
Title: _____
Date: _____

RATE ADJUSTMENT RIDER – NORTHWEST FLORIDA DIVISION

Applicability

Electric service under all rate schedules for the Northwest Florida Division, which specify that rates are subject to adjustment in accordance with the provisions of the Company's Rate Adjustment Rider.

Total Purchased Power Cost Recovery Clause

The total purchased power cost adjustment shall be applied to each kilowatt hour delivered and shall be computed in accordance with the formula prescribed by the Florida Public Service commission. The total purchased power cost adjustment for the period January 1, 2025 through December 31, 2025 is as follows:

<u>Rate Class</u>	<u>Rate Schedule</u>	<u>Levelized Adjustment</u>
Residential (1st 1000 KWH's)	RS	7.505¢ / KWH
Residential (above 1000 KWH's)	RS	8.755¢ / KWH
General Service	GS	7.890¢ / KWH
General Service-Demand	GSD	7.392¢ / KWH
Lighting Service	LS	5.872¢ / KWH
General Service-Large Demand	GSLD	7.176¢ / KWH
General Service-Large Demand 1	GSLD 1	Not Applicable At This Time

<u>Time of Use Rate Class</u>	<u>Rate Schedule</u>	<u>Levelized Adjustment</u>	
		On-Peak	Off Peak
Residential TOU	RST - EXP	0.000¢ / KWH	0.000¢ / KWH
General Service TOU	GST - EXP	0.000¢ / KWH	0.000¢ / KWH
General Service-Demand TOU	GSDT – EXP	0.000¢ / KWH	0.000¢ / KWH
General Service-Large Demand TOU	GSLDT – EXP	0.000¢ / KWH	0.000¢ / KWH

Energy Conservation Cost Recovery Clause

Each base energy rate per KWH of the above rate schedules for the period January 1, 2025 through December 31, 2025 shall be increased by 0 .121 ¢/KWH of sales to recover conservation related expenditures by the Company. This adjustment is determined in accordance with the formula and procedures specified by the Florida Public Service Commission.

The Energy Conservation Cost Recovery Clause will not apply to the GSLD-1 rate class.

Tax Cost Recovery

There will be added to all bills rendered for electric service a proportionate share of all license fees and taxes imposed by any governmental authorities after November 1, 1946, to an extent sufficient to cover excess increased taxes or license fees.

RATE ADJUSTMENT RIDER – NORTHEAST FLORIDA DIVISION

Applicability

Electric service under all rate schedules for the Northeast Florida Division which specify that rates are subject to adjustment in accordance with the provisions of the Company's Rate Adjustment Rider.

Total Purchased Power Cost Recovery Clause

The total purchased power cost adjustment shall be applied to each kilowatt hour delivered and shall be computed in accordance with the formula prescribed by the Florida Public Service Commission. The total purchased power cost adjustment for the period January 1, 2025 through December 31, 2025 is as follows:

<u>Rate Class</u>	<u>Rate Schedule</u>	<u>Levelized Adjustment</u>
Residential (1 st 1000 KWH's)	RS	7.505¢ / KWH
Residential (above 1000 KWH's)	RS	8.755¢ / KWH
General Service	GS	7.890¢ / KWH
General Service –Demand	GSD	7.392¢ / KWH
General Service –Large Demand	GSLD	7.176¢ / KWH
Lighting Service	LS	5.872¢ / KWH
General Service Large Demand 1 (Over 10.00 KW billed annually)	GSLD 1	Generation Demand \$ 4.501/ KW*
Standby	SB	2.937\$ / KW

*Estimated for informational purposes only,
Monthly rate will be billed at actual cost.

Energy Conservation Cost Recovery Clause

Each base energy rate per KWH of the above rate schedules for the period January 1, 2025 through December 31, 2025 shall be increased by 0.121 ¢ / KWH of sales to recover conservation related expenditures by the Company. This adjustment is determined in accordance with the formula and procedures specified by the Florida Public Service Commission.

The Energy Conservation Cost Recovery Clause will not apply to the GSLD-1 rate class.

Tax Recovery

There will be added to all bills rendered for electric service a proportionate share of all license fees and taxes imposed by any governmental authorities after January 1, 1945, to an extent sufficient to cover excess increased taxes or license fee.

NON-FIRM ENERGY PROGRAM NFEP-EXP (EXPERIMENTAL) - CLOSED

Availability

Available within the territory served by the Company in Jackson, Calhoun, and Liberty Counties and on Amelia Island in Nassau County. This service is limited to Customers in the GSLD1 or Standby rate class. The Rate Schedule is closed to new Customers and shall expire within 90 days written notice by the Company to participating Customers and will expire in its entirety by September 1, 2025.

Applicability

Applicable to Customers which are self-generators with dispatchable generation and are eligible for Rate Schedule GSLD1 or Standby, or who have executed a Special Contract approved by the Commission. Eligible Customers would nominate, in accordance with the procedures outlined below, an amount of electric load they commit to purchase that is above and in addition to the Customer's established baseline. Non-Firm (NF) Energy nominations must be made in 1,000 KW increments and is currently limited to a minimum of 1,000 kW and maximum of 15,000 kW. The Customer is not obligated to nominate NF Energy for any specific period but must nominate a minimum of 1,500 MWh per year.

The default period for NF Energy nominations will be 7 days. Nominations for longer periods, e.g. monthly, will be made available when market conditions warrant. The same procedure for nominations and acceptance will apply to all periods. Customer may nominate NF Energy for on-peak hours, off-peak hours, or all hours. On-peak hours are Hour Ending (H.E.) 08:00 to H.E 23:00 weekdays and off-peak hours are H.E. 24:00 to HE 07:00 and all hours on weekends and established holidays. Times shown are Eastern Standard or Daylight Savings time. On-peak and off-peak hours are subject to change.

Once the Company confirms the Customer's nomination, the Customer is obligated to pay for all NF Energy nominated at the offered rate regardless of whether the Customer takes all NF Energy nominated for the month, unless recalled in accordance with NF Recall provisions.

Monthly Rate

The rates and all other terms and conditions of the Customer's otherwise applicable rate schedule shall be applicable under this program.

All NF Energy shall be charged at the hourly price, in \$/MWh, as offered by the Company. Once nominated by the Customer and accepted by the Company, the Customer is responsible to pay the full NF Energy Charge for the nomination period regardless of whether the Customer takes all NF Energy nominated for the month. Any purchases that exceed the combined total of the Customer's baseline and NF Energy nominations will be billed based on the Customer's otherwise applicable rate. The NF Energy charges are in addition to the charges based on the Customers otherwise applicable rate.

Monthly NF Administrative Charge:
\$0.00 per Customer per month

NON-FIRM ENERGY PROGRAM NFEP-EXP (EXPERIMENTAL) - CLOSED

Monthly NF Demand Charge:

\$0.00 per kW of NF demand

Monthly Rate

NF Energy Charge:

Amount as offered and accepted for each nomination

Monthly NF Demand

The Monthly NF Demand shall equal the maximum hour of NF Energy nominated by the Customer for the calendar month.

Minimum Monthly Bill

The Minimum Monthly Bill shall consist of the Monthly NF Administrative Charge plus applicable taxes and fees.

Term of Service

The Customer agrees to a minimum of 12 months of service under the Program. Service will continue thereafter until the Customer submits to the Company a written notice of termination. Service will discontinue at the end of the calendar month that notice of termination is received.

Nomination and Acceptance Procedure

1. By 10:00 AM each Friday, or when NF Energy is available, the Company will provide the Customer with NF Energy price quotations for the following period beginning 0:00 (midnight) the following Sunday (time period is Monday 00:00 – Sunday 24:00).
2. The Customer will submit a NF Energy nomination schedule to the Company by 2:00 PM of the same day that the offer is submitted.
3. NF Energy nominations are accepted once the Company confirms receipt of the nomination. The Company will then schedule delivery of the NF Energy, if any, beginning 0:00 (midnight) the following Sunday.

Nomination Recall Provisions:

Once accepted, nominations by Customer may only be withdrawn if a Force Majeure is declared. A Force Majeure may be declared by the Customer if the Customer's equipment suffers major failure such that the Customer is prevented from taking the NF Energy. In such case, the Customer will notify the Company's designated contact by approved method as soon as condition is known and the Company will attempt to withdraw the scheduled delivery of NF Energy. If possible, the Customer will no longer be responsible for purchasing the balance of NF Energy nominated during the event. Customer may declare Force Majeure a maximum of once per month.

Company may terminate NF Energy delivery at any time due to system emergencies or unusual pricing by notifying Customer of such termination, and Company has no obligation to deliver NF Energy.

STORM PROTECTION PLAN COST RECOVERY CLAUSE

Applicability

Electric service under all rate schedules.

Storm Protection Plan Cost Recovery Clause

The Storm Protection Plan Cost Recovery (SPPCRC) Factors shall be applied to the Customer's total kilowatt hour billed. This factor is designed to recover expenditures incurred by the Company related to the protection and hardening of the grid from storms and other extreme weather events. This adjustment is determined in accordance with the formula and procedures prescribed by the Florida Public Service Commission as set forth in Rule 25-6.031, F.A.C.

The total Storm Protection Plan Cost Recovery factors for the period January 1, 2025 through December 31, 2025 are as follows:

<u>Rate Schedule</u>	<u>SPP Factors per KWH</u>
Residential	0.9970¢ / KWH
General Service	1.1000¢ / KWH
General Service Demand	0.5940¢ / KWH
General Service Large Demand	0.5080¢ / KWH
Industrial/Standby	1.4020¢ / KWH
Lighting Service	6.1770¢ / KWH

STORM RECOVERY SURCHARGE

Hurricanes Michael Surcharge:

Applicability:

Electric service under all rate schedules.

Description:

This surcharge is for recovery of storm costs and will be recovered from November 2020 through December 2025.

Rate Class – GSLD-1 - \$190,208 total, annually to be allocated across the GSLD-1 rate class.

All other Rate Schedules - The surcharge of 1.280¢/ KWH will be applied to each kilowatt hour billed from November 2020 through December 2025.

INDEX OF STANDARD FORMS

<u>Extension of Facilities Agreement</u>	EFA	8.001
<u>Deposit of Facilities Agreement</u>	DFA	8.003
<u>Interconnection of Customer Owned-Renewable Generation Systems Application</u>		8.005
<u>Reserved for Future Use</u>		8.007
<u>Standard Interconnection Agreement Tier 1 Renewable Generation Systems</u>		8.008
<u>Standard Interconnection Agreement Tier 2 Renewable Generation Systems</u>		8.009
<u>Standard Interconnection Agreement Tier 3 Renewable Generation Systems</u>		8.017

STANDARD FORMS
EXTENSION OF FACILITIES AGREEMENT

FLORIDA PUBLIC UTILITIES COMPANY
EXTENSION OF FACILITIES AGREEMENT

This Agreement, executed in duplicate as of the __ day of _____, 20__, by and between Florida Public Utilities Company, a Florida Corporation, hereinafter referred to as the “Company”, party of the first part, and _____ hereinafter referred to as the “Customer”, party of the second part, witnesseth:

Whereas, the Customer is desirous of securing an extension or increase of the facilities of the Company as hereinafter described; and whereas, the Company is willing to make such extension or increase;

Now, therefore, in consideration of the respective and mutual covenants and agreements contained herein and hereinafter set forth, the parties hereto agree with each other as follows:

1. The Company will extend or increase its facilities as follows:

The Company will commence the extension or increase of its facilities forthwith after the execution of this Agreement and use its best efforts to complete the extension or increase of its facilities as soon as reasonably possible; provided, however, that the parties expressly agree that the Company shall not be liable or responsible for any delay caused by or resulting from shortages or unavailability of material or labor, or from any other hindrance or delay beyond the control of the Company.

2. To compensate the Company for the cost and expense of the aforesaid extension or increase of its facilities, the Customer simultaneously with the execution of this Agreement has paid to the Company the sum of \$_____, the receipt of which hereby is acknowledged by the Company. The parties agree that said sum was paid by the Customer to and received by the Company without the right of any rebate, credit, reduction or adjustment in favor of either party.

3. The parties agree that the Company shall at all times have title to and keep ownership and control in and over the aforesaid extended or increased facilities, including but not limited to all new materials and equipment installed therein; and the parties agree further that the Company shall have the sole and exclusive right to use the extended or increased facilities for the purpose of serving other Customers of the Company.

STANDARD FORMS
EXTENSION OF FACILITIES AGREEMENT (Continued)

4. After the extension or increase of the facilities described above, the Customer agrees that subject to all applicable terms, provisions, rights, duties and penalties, the Customer will in the usual manner and at the usual times pay for the utilities and services delivered to the Customer by means of the extended or increased facilities at the regular franchise or at special contract rates, whichever is applicable.

5. The parties agree that no representation, warranty, conditions or agreement of any kind or nature whatsoever shall be binding upon either of the parties hereto unless incorporated in this Agreement; and the parties agree further that this Agreement covers and includes the entire agreement between the parties. The parties agree that all covenants and agreements contained herein shall extend to, be obligatory upon and inure to the benefit of the parties hereto and their respective heirs, legal representatives, successors and assigns; provided, however, that the Customer may not transfer or assign all or any part of this Agreement or any right which he may obtain hereunder without first obtaining the written consent of the Company.

In witness whereof, the parties hereto have executed this Agreement as of the day and year hereinbefore first written.

Customer _____

FLORIDA PUBLIC UTILITIES COMPANY

By _____
Title

By _____
Its Agent

STANDARD FORMS
DEPOSIT OF FACILITIES AGREEMENT

FLORIDA PUBLIC UTILITIES COMPANY
DEPOSIT OF FACILITIES AGREEMENT

This Agreement, executed in duplicate as of the ____ day of _____, 20____, by and between Florida Public Utilities Company, a Florida Corporation, hereinafter referred to as the “Company”, party of the first part, and _____ hereinafter referred to as the “Customer”, party of the second part, witnesseth:

Whereas, the Customer is desirous of securing an extension or increase of the facilities of the Company as hereinafter described; and whereas, the Company is willing to make such extension or increase;

Now, therefore, in consideration of the respective and mutual covenants and agreements contained herein and hereinafter set forth, the parties hereto agree with each other as follows:

1. The Company will extend or increase its facilities as follows:

The Company will commence the extension or increase of its facilities forthwith after the execution of this Agreement and use its best efforts to complete the extension or increase of its facilities as soon as reasonably possible; provided, however, that the parties expressly agree that the Company shall not be liable or responsible for any delay caused by or resulting from shortages or unavailability of material or labor, or from any other hindrance or delay beyond the control of the Company.

2. To compensate the Company for the cost and expense of the aforesaid extension or increase of its facilities in accordance with the Company’s Rules and Regulations for extensions, the Customer simultaneously with the execution of this Agreement has paid to the Company the sum of \$_____, the receipt of which hereby is acknowledged by the Company. The parties agree that said sum was paid by the Customer to and received by the Company in accordance with the Company’s Rules and Regulations for service requiring extension of facilities within the service area of the Company in _____ County, Florida. The Company’s Rules and Regulations as filed with and approved by the Florida Public Service Commission are made a part of this Agreement.

3. The parties agree that the Company shall at all times have title to and keep ownership and control in and over the aforesaid extended or increased

*STANDARD FORMS
DEPOSIT OF FACILITIES AGREEMENT (Continued)*

facilities, including but not limited to all new materials and equipment installed therein; and the parties agree further that the Company shall have the sole and exclusive right to use the extended or increased facilities for the purpose of serving other Customers of the Company.

4. After the extension or increase of the facilities described above, the Customer agrees that subject to all applicable terms, provisions, rights, duties and penalties, the Customer will in the usual manner and at the usual times pay for the utilities and services delivered to the Customer by means of the extended or increased facilities in accordance with the Company's tariffs filed with and approved by the Florida Public Service Commission.

5. The parties agree that no representation, warranty, conditions or agreement of any kind or nature whatsoever shall be binding upon either of the parties hereto unless incorporated in this Agreement; and the parties agree further that this Agreement covers and includes the entire agreement between the parties. The parties agree that all covenants and agreements contained herein shall extend to, be obligatory upon and inure to the benefit of the parties hereto and their respective heirs, legal representatives, successors and assigns; provided, however, that the Customer may not transfer or assign all or any part of this Agreement or any right which he may obtain hereunder without first obtaining the written consent of the Company.

In witness whereof, the parties hereto have executed this Agreement as of the day and year hereinbefore first written.

Customer _____ FLORIDA PUBLIC UTILITIES COMPANY

By _____ By _____
Title Its Agent

*STANDARD FORMS / APPLICATION
INTERCONNECTION OF CUSTOMER-OWNED*

**RENEWABLE GENERATION SYSTEMS APPLICATION
INTERCONNECTION OF CUSTOMER OWNED RENEWABLE
GENERATION SYSTEMS**

TIER 1 – 10 KW or Less

TIER 2 – Greater than 10 KW and Less Than or Equal to 100 KW

TIER 3 – Greater than 100 KW and Less Than or Equal to 2 MW

Florida Public Utilities Company Customers who install Customer-owned renewable generation systems and desire to interconnect those facilities with the FPUC electrical system are required to complete this application. This application can be obtained from the local FPU office or can be downloaded from the FPUC website (www.fpuc.com). When the completed application and fees are returned to FPUC, the process of completing the appropriate Tier 1, Tier 2 or Tier 3 Interconnection Agreement can begin. The Interconnection Agreements may be obtained at the local FPUC office. Details for interconnection agreements may be found as defined in Rule 25-6.065, Florida Administrative Code or within the Florida Public Utilities Company Interconnection Agreement.

1. Customer Information

Name: _____

Mailing Address: _____

City: _____ State: _____ Zip Code: _____

Phone Number: _____ Alternate Phone Number: _____

Email Address: _____ Fax Number: _____

2. Facility Information

Facility Location: _____

FPUC Account Number (if available): _____

Manufacturers Name/Address: _____

Reference or Model Number: _____

Serial Number: _____

*INTERCONNECTION OF CUSTOMER-OWNED
RENEWABLE GENERATION SYSTEMS APPLICATION (Continued)*

3. Facility Rating Information

Gross Power Rating: _____ (“Gross power rating” means the total manufacturer’s AC nameplate generating capacity of an on-site Customer-owned renewable generation system that will be interconnected to and operate in parallel with the investor-owned utility’s distribution facilities. For inverter-based systems, the AC nameplate generating capacity shall be calculated by multiplying the total installed DC nameplate generating capacity by .85 in order to account for losses during the conversion from DC to AC.

Fuel or Energy Source: _____

Anticipated In- Service Date: _____

4. Application Fee

The application fee is based on the Gross Power Rating and must be submitted with this application. There is no application fee for Tier 1 installations. The non-refundable application fee is \$350 for Tier 2 and Tier 3 installations.

5. Interconnection Study Fee

For Tier 3 installations that require an interconnection study, as determined by the Company, the Customer will pay \$2,000 prior to the initiation of the interconnection study. The total cost to the Customer will not exceed this amount. Should the actual interconnection study cost be less than \$2,000 the Customer will be refunded the difference.

6. Required Documentation

Before the Interconnection Agreement may become effective, the Documentation listed in this Section must be provided to the Company by the Customer. The Documentation listed does not need to accompany the Application but must be received before the Interconnection Agreement will be executed by the Company.

- A. Documentation that the installation complies with:
 - 1. IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems.
 - 2. IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
 - 3. UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use with Distributed Energy Resources.
- B. Documentation that the Customer-owned renewable generation has been inspected and approved by local code officials prior to its operation in parallel with the Company system to ensure compliance with applicable local codes.
- C. Proof of general liability insurance for Tier 2 generators (\$1,000,000) or Tier 3 generators (\$2,000,000). Not required for Tier 1 generators.
- D. Copy of any lease agreements if the Customer is leasing facility from third party.

RESERVED FOR FUTURE USE

STANDARD FORMS
STANDARD INTERCONNECTION AGREEMENT - TIER 1

STANDARD INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)

This agreement made and entered into as of this __ day of _____,
_____ by and between _____ hereinafter known as the “Customer”
and Florida Public Utilities Company hereinafter know as the “Company”. This agreement is made
in accordance with Florida Public Commission Rule 25-6.065 F.A.C., Interconnection and Net
Metering of Customer-Owned Renewable Generation and under the terms and conditions as
approved by the Florida Public Service Commission pursuant to Rule 25-6.065(3), F.A.C.

1. The Customer’s renewable generation system is within the Company service territory and
is located at:

and should be installed and operational by:

_____, _____.

2. Customer will ensure the installation will meet or exceed all requirements noted below, will
provide the Company with reasonable notification prior to the operation of the system and
will assist the Company in verifying that the installation complies with the agreement prior
to operating in parallel with the Company’s electric system.

3. The Customer’s renewable generation system is described as follows:

- a. Equipment Manufacturers Name and Address:

- b. Manufacturers Reference Number, Serial Number, Type, Style, Model, Etc.

- c. Name Plate Rating (KW and Voltage):

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continuea)*

4. Standard Interconnection Agreement Requirements – To qualify for expedited interconnection as a Tier 1 generator pursuant to Rule 25-6.065, F.A.C., the Facility must:
 - (a) Comply with IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems.
 - (b) Comply with IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
 - (c) Comply with UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.
 - (d) Have a Gross Power Rating that does not exceed 90% of the Customer's utility distribution service rating.
 - (e) Have a Gross Power Rating of 10 KW or less.

5. Customer Qualifications and Fees – The Customer shall comply with the following to qualify as a Tier 1 generator pursuant to Rule 25-6.065, F.A.C.:
 - (a) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in Section (4).
 - (b) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to Section (5) (a) that performs the function of automatically isolating the Customer-owned generation equipment from the electric grid in the event the electric grid loses power.
 - (c) Provided the Customer-owned renewable generation equipment complies with Sections (4) and (5) (a), (b), the Company shall not require further design review, testing, or additional equipment other than that provided for in Section (9).
 - (d) Tier 1 Customers who request interconnection of Customer-owned renewable generation shall not be charged fees in addition to those charged to other retail Customers without self-generation, including application fees.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continued)*

6. Inspection Requirements – Prior to operating the Customer system in parallel with Company’s electric system, the Customer will:
 - (a) Have the Customer-owned renewable generation inspected and approved by local code officials prior to its operation in parallel with the Company system to ensure compliance with applicable local codes.
 - (b) Make provisions that permit the Company to inspect Customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with Sections (4) and (5). The Customer shall notify the Company at least 10 days prior to initially placing Customer equipment and protective apparatus in service, and the Company shall have the right to have personnel present on the in-service date. If the Customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the Customer must notify the Company by submitting a new application specifying the modifications at least 30 days prior to making the modifications.
 - (c) Provide for protection of the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the Company system in delivering and restoring power; and is responsible for ensuring that Customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer’s instructions to ensure that it is operating correctly and safely.

7. Indemnity for Loss to Third Parties - The Customer shall hold harmless and indemnify the Company for all loss to third parties resulting from the operation of the Customer-owned renewable generation, except when the loss occurs due to the negligent actions of the Company. The Company shall hold harmless and indemnify the Customer for all loss to third parties resulting from the operation of the Company’s system, except when the loss occurs due to the negligent actions of the Customer.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continuea)*

8. Customer Insurance Requirements – The Customer owning a Tier 1 generator is not required by rule to obtain general liability insurance for damage to persons or property as a result of the operation of the generator. However, the Company strongly recommends that a Tier 1 Customer carry an appropriate level of liability insurance.

9. Manual Disconnect Switch - Inverter-based Tier 1 Customer-owned renewable generation systems shall be exempt from this requirement. However, the Company recommends that the Customer install, at the Customer's expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the Customer-owned renewable generation and any Customer wiring connected to the Company's system. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the Company and capable of being locked in the open position with a single Company padlock. Should a main disconnect switch not be installed, removal of the electric meter and disconnection of electric service may be used to isolate the Customer owned generation for the electric grid.

10. Disconnection From Customer System - The Company may open the manual disconnect switch pursuant to the conditions set forth below in (10) (a) – (10) (d), isolating the Customer-owned renewable generation, without prior notice to the Customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the Company shall at the time of disconnection leave a door hanger notifying the Customer that their Customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The Company shall reconnect the Customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.
 - a. Emergencies or maintenance requirements on the Company's electric system;

 - b. Hazardous conditions existing on the Company system due to the operation of the Customer's generating or protective equipment as determined by the Company;

 - c. Adverse electrical effects, such as power quality problems, on the electrical equipment of the Company's other electric consumers caused by the Customer-owned renewable generation as determined by the Company;

 - d. Failure of the Customer to maintain the required insurance coverage (if required).

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continuea)*

11. Administrative Requirements

- (a) The Company shall maintain on its website a downloadable application for interconnection of Customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the Company shall provide a hard copy of the application within 5 business days.
- (b) Within 10 business days of receipt of the Customer's application, the Company shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the Company shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the Customer-owned renewable generation necessary for the Company to confirm compliance with Sections (4) through (10).
- (c) The Standard Interconnection Agreement shall be executed by the Company within 30 calendar days of receipt of a completed application.
- (d) The Customer must execute the Standard Interconnection Agreement and return it to the Company at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the Company within 30 calendar days of receipt of the Customer's executed Standard Interconnection Agreement. If the inspection is delayed at the Customer's request, the Customer shall contact the utility to reschedule an inspection. The Company shall reschedule the inspection within 10 business days of the Customer's request.

12. Net Metering

- (a) The Company shall enable each Customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.
- (b) The Company shall install, at no additional cost to the Customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the Customer from the investor-owned utility and the electricity generated by the Customer and delivered to the investor-owned utility's electric grid.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continuea)*

12. Net Metering (continued)

- (c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.
- (d) The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation in accordance with normal billing practices.
- (e) During any billing cycle, excess Customer-owned renewable generation delivered to the Company's electric grid shall be credited to the Customer's energy consumption for the next month's billing cycle.
- (f) Energy credits produced pursuant to Section (12) (e) shall accumulate and be used to offset the Customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the Company shall pay the Customer for any unused energy credits at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (g) When a Customer leaves the system, that Customer's unused credits for excess kWh generated shall be paid to the Customer at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (h) Regardless of whether excess energy is delivered to the Company's electric grid, the Customer shall continue to pay the applicable Customer charge and applicable demand charge (if applicable) for the maximum measured demand during the billing period. The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation at the Company's otherwise applicable rate schedule. The Customer may at their sole discretion choose to take service under the Company's standby or supplemental service rate, if available.

13. Renewable Energy Certificates - Customers shall retain any Renewable Energy Certificates associated with the electricity produced by their Customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the Customer's expense, unless otherwise determined during negotiations for the sale of the Customer's Renewable Energy Certificates to the Company.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW OR LESS)
(Continued)*

14. Change of Ownership – This agreement shall not be assigned or transferred without prior written consent of the Company. Should there be a change in ownership; the Customer shall provide the Company with 30 day notice prior to the change. The Company will contact the new owner prior to the end of the 30 days in order to execute a new agreement. The new owner will not be entitled to operate the generator in parallel with the Company system or be net metered until a new agreement is executed by both parties. However, this agreement shall inure to the benefit of and binding upon the respective heirs, legal representatives, successors and assigns of the parties involved until a new agreement is executed.

15. No Extension of Credit – In executing this agreement, the Company does not, nor should it be construed to extend credit or financial support for the benefit of any third parties lending money to or having other transactions with the Customer or any assignee of this agreement.

16. Applicability of Tariff – The Company’s tariff and associated technical terms and abbreviations, general rules, regulations and standard electric service requirements are incorporated herein by reference. In the event that this tariff and the Interconnection Agreement is revised due to rule changes approved by the Florida Public Service Commission, the Company and the Customer agree to replace this agreement with an amended agreement that complies with the amended Florida Public Service Commission rules.

17. Entire Agreement – This agreement supersedes all previous agreements or representations, either written or oral, heretofore in effect between the Company and the Customer, made in respect to matters herein contained, and when duly executed, this agreement constitutes the entire agreement between the parties.

18. Termination – Upon termination of this agreement, the Company shall open and padlock the manual disconnect switch, if applicable, and remove any additional kilowatt-hour meter and associated Company equipment. At the Customer’s expense, the Customer agrees to permanently isolate the Facility from the Company’s electric service grid. The Customer shall notify the Company in writing within ten (10) business days that the isolation procedure has been completed.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW or Less)
(Continuea)*

19. Retail Purchase of Electricity - “Customer-owned renewable generation” means an electric generating system located on a Customer’s premise that is primarily intended to offset part or all of the Customer’s electricity requirements with renewable energy. The term “Customer-owned renewable generation” does not preclude the Customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions does not include the retail purchase of electricity from the third party.
20. The Customer agrees to indemnify and hold harmless the Company, its subsidiaries or affiliates, and their respective employees, officers and directors, against any and all liability, loss, damage, cost or expense which the Company, it subsidiaries, affiliates, and their respective employees, officers and directors may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Customer under the obligations of this agreement. The Company agrees to indemnify and hold harmless the Customer, against any and all liability, loss, damage, cost or expense which the Customer may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Company under the obligations of this agreement.
21. Communications, either emergency or routine, related to this agreement or operation of the installation shall be made to the following parties:

Company:

Customer:

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 1 RENEWABLE GENERATION SYSTEMS (10 KW or Less)
(Continued)*

22. Dispute Resolution – The Company and Customer may seek resolution of disputes arising out of this interpretation of this agreement pursuant to Rule 25-22.032, F.A.C., Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

IN WITNESS WHEREOF, the Customer and the Company execute this Agreement this _____ day of _____, _____.

Title: _____

WITNESS:

FLORIDA PUBLIC UTILITIES COMPANY
COMPANY

By: _____

Title: _____

Date: _____

Date: _____

WITNESS:

CUSTOMER

By: _____

Title: _____

Date: _____

STANDARD FORMS
STANDARD INTERCONNECTION AGREEMENT – TIER 2

STANDARD INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED TIER 2
RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)

This agreement made and entered into as of this _____ day of _____, _____ by and between _____ hereinafter known as the “Customer” and Florida Public Utilities Company hereinafter know as the “Company”. This agreement is made in accordance with Florida Public Commission Rule 25-6.065 F.A.C., Interconnection and Net Metering of Customer-Owned Renewable Generation and under the terms and conditions as approved by the Florida Public Service Commission pursuant to Rule 25-6.065(3), F.A.C.

1. The Customer’s renewable generation system is within the Company service territory and is located at:

and should be installed and operational by:

_____, _____.

2. Customer will ensure the installation will meet or exceed all requirements noted below, will provide the Company with reasonable notification prior to the operation of the system and will assist the Company in verifying that the installation complies with the agreement prior to operating in parallel with the Company’s electric system.

3. The Customer’s renewable generation system is described as follows:

- a. Equipment Manufacturers Name and Address:

- b. Manufacturers Reference Number, Serial Number, Type, Style, Model, Etc.

- c. Name Plate Rating (KW and Voltage):

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

4. Standard Interconnection Agreement Requirements – To qualify for expedited interconnection as a Tier 2 generator pursuant to Rule 25-6.065, F.A.C., the Facility must:
 - (a) Comply with IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems.
 - (b) Comply with IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
 - (c) Comply with UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.
 - (d) Have a Gross Power Rating that does not exceed 90% of the Customer’s utility distribution service rating.
 - (e) Have a Gross Power Rating greater than 10 KW and less than or equal to 100 KW.

5. Customer Qualifications and Fees – The Customer shall comply with the following to qualify as a Tier 2 generator pursuant to Rule 25-6.065, F.A.C.:
 - (a) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in Section (4).
 - (b) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to Section (5) (a) that performs the function of automatically isolating the Customer-owned generation equipment from the electric grid in the event the electric grid loses power.
 - (c) Provided the Customer-owned renewable generation equipment complies with Sections (4) and (5) (a), (b), the Company shall not require further design review, testing, or additional equipment other than that provided for in Section (9).
 - (d) Tier 2 Customers who request interconnection of Customer-owned renewable generation shall be charged a one-time non-refundable application fee of \$350.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continued)*

6. Inspection Requirements – Prior to operating the Customer system in parallel with Company’s electric system, the Customer will:
 - (a) Have the Customer-owned renewable generation inspected and approved by local code officials prior to its operation in parallel with the Company system to ensure compliance with applicable local codes.
 - (b) Make provisions that permit the Company to inspect Customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with Sections (4) and (5). The Customer shall notify the Company at least 10 days prior to initially placing Customer equipment and protective apparatus in service and the Company shall have the right to have personnel present on the in-service date. If the Customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the Customer must notify the Company by submitting a new application specifying the modifications at least 30 days prior to making the modifications.
 - (c) Provide for protection of the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the Company system in delivering and restoring power; and is responsible for ensuring that Customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer’s instructions to ensure that it is operating correctly and safely.
7. Indemnity for Loss to Third Parties - The Customer shall hold harmless and indemnify the Company for all loss to third parties resulting from the operation of the Customer-owned renewable generation, except when the loss occurs due to the negligent actions of the Company. The Company shall hold harmless and indemnify the Customer for all loss to third parties resulting from the operation of the Company’s system, except when the loss occurs due to the negligent actions of the Customer.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

8. Customer Insurance Requirements – The Customer owning a Tier 2 generator is required by rule to obtain general liability insurance for personal and property damage in the amount of no less than one million dollars (\$1,000,000) as a result of the operation of the generator. Prior to parallel operation, the Customer shall provide initial proof of insurance or sufficient guarantee and proof of self insurance, evidencing the generator. The Customer shall continue to provide proof of continuing insurance within 30 days of any policy renewal.
9. Manual Disconnect Switch – Customer’s operating a Tier 2 generator shall install, at the Customer’s expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the Customer-owned renewable generation and any Customer wiring connected to the Company’s system. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the Company and capable of being locked in the open position with a single Company padlock.
10. Disconnection From Customer System - The Company may open the manual disconnect switch pursuant to the conditions set forth below in Sections (10) (a) – (10) (d), isolating the Customer-owned renewable generation, without prior notice to the Customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the Company shall at the time of disconnection leave a door hanger notifying the Customer that their Customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The Company shall reconnect the Customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.
 - a. Emergencies or maintenance requirements on the Company’s electric system;
 - b. Hazardous conditions existing on the Company system due to the operation of the Customer’s generating or protective equipment as determined by the Company;
 - c. Adverse electrical effects, such as power quality problems, on the electrical equipment of the Company’s other electric consumers caused by the Customer-owned renewable generation as determined by the Company;
 - d. Failure of the Customer to maintain the required insurance coverage.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continued)*

11. Administrative Requirements

- (a) The Company shall maintain on its website a downloadable application for interconnection of Customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the Company shall provide a hard copy of the application within 5 business days.
- (b) Within 10 business days of receipt of the Customer's application, the Company shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the Company shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the Customer-owned renewable generation necessary for the Company to confirm compliance with Sections (4) through (10).
- (c) The Standard Interconnection Agreement shall be executed by the Company within 30 calendar days of receipt of a completed application.
- (d) The Customer must execute the Standard Interconnection Agreement and return it to the Company at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the Company within 30 calendar days of receipt of the Customer's executed Standard Interconnection Agreement. If the inspection is delayed at the Customer's request, the Customer shall contact the utility to reschedule an inspection. The Company shall reschedule the inspection within 10 business days of the Customer's request.

12. Net Metering

- (a) The Company shall enable each Customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.
- (b) The Company shall install, at no additional cost to the Customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the Customer from the investor-owned utility and the electricity generated by the Customer and delivered to the investor-owned utilities electric grid.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

12. Net Metering (continued)

- (c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.
- (d) The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation in accordance with normal billing practices.
- (e) During any billing cycle, excess Customer-owned renewable generation delivered to the Company's electric grid shall be credited to the Customer's energy consumption for the next month's billing cycle.
- (f) Energy credits produced pursuant to Section (12) (e) shall accumulate and be used to offset the Customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the Company shall pay the Customer for any unused energy credits at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (g) When a Customer leaves the system, that Customer's unused credits for excess kWh generated shall be paid to the Customer at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (h) Regardless of whether excess energy is delivered to the Company's electric grid, the Customer shall continue to pay the applicable Customer charge and applicable demand charge (if applicable) for the maximum measured demand during the billing period. The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation at the Company's otherwise applicable rate schedule. The Customer may at their sole discretion choose to take service under the Company's standby or supplemental service rate, if available.

13. Renewable Energy Certificates - Customers shall retain any Renewable Energy Certificates associated with the electricity produced by their Customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the Customer's expense, unless otherwise determined during negotiations for the sale of the Customer's Renewable Energy Certificates to the Company.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

14. Change of Ownership – This agreement shall not be assigned or transferred without prior written consent of the Company. Should there be a change in ownership; the Customer shall provide the Company with 30 day notice prior to the change. The Company will contact the new owner prior to the end of the 30 days in order to execute a new agreement. The new owner will not be entitled to operate the generator in parallel with the Company system or be net metered until a new agreement is executed by both parties. However, this agreement shall inure to the benefit of and binding upon the respective heirs, legal representatives, successors and assigns of the parties involved until a new agreement is executed.
15. No Extension of Credit – In executing this agreement, the Company does not, nor should it be construed to extend credit or financial support for the benefit of any third parties lending money to or having other transactions with the Customer or any assignee of this agreement.
16. Applicability of Tariff – The Company’s tariff and associated technical terms and abbreviations, general rules, regulations and standard electric service requirements are incorporated herein by reference. In the event that this tariff and the Interconnection Agreement is revised due to rule changes approved by the Florida Public Service Commission, the Company and the Customer agree to replace this agreement with an amended agreement that complies with the amended Florida Public Service Commission rules.
17. Entire Agreement – This agreement supersedes all previous agreements or representations, either written or oral, heretofore in effect between the Company and the Customer, made in respect to matters herein contained, and when duly executed, this agreement constitutes the entire agreement between the parties.
18. Termination – Upon termination of this agreement, the Company shall open and padlock the manual disconnect switch, if applicable, and remove any additional kilowatt-hour meter and associated Company equipment. At the Customer’s expense, the Customer agrees to permanently isolate the Facility from the Company’s electric service grid. The Customer shall notify the Company in writing within ten (10) business days that the isolation procedure has been completed.

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEM
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

19. Retail Purchase of Electricity - “Customer-owned renewable generation” means an electric generating system located on a Customer’s premise that is primarily intended to offset part or all of the Customer’s electricity requirements with renewable energy. The term “Customer-owned renewable generation” does not preclude the Customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions but does not include the retail purchase of electricity from the third party.
20. The Customer agrees to indemnify and hold harmless the Company, its subsidiaries or affiliates, and their respective employees, officers and directors, against any and all liability, loss, damage, cost or expense which the Company, it subsidiaries, affiliates, and their respective employees, officers and directors may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Customer under the obligations of this agreement. The Company agrees to indemnify and hold harmless the Customer, against any and all liability, loss, damage, cost or expense which the Customer may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Company under the obligations of this agreement.
21. Communications, either emergency or routine, related to this agreement or operation of the installation shall be made to the following parties:

Company:

Customer:

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 2 RENEWABLE GENERATION SYSTEMS
(Greater than 10 KW and Less than or Equal to 100 KW)
(Continuea)*

22. Dispute Resolution – The Company and Customer may seek resolution of disputes arising out of this interpretation of this agreement pursuant to Rule 25-22.032, F.A.C., Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

IN WITNESS WHEREOF, the Customer and the Company execute this Agreement this _____ day of _____, _____.

Title: _____

WITNESS:

FLORIDA PUBLIC UTILITIES
COMPANY

By: _____

Title: _____

Date: _____

Date: _____

WITNESS:

CUSTOMER

By: _____

Title: _____

Date: _____

STANDARD FORMS
STANDARD INTERCONNECTION AGREEMENT - TIER 3

**STANDARD INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 3 RENEWABLE GENERATION SYSTEMS (Greater than 100 KW and
Less than or Equal to 2 MW)**

This agreement made and entered into as of this ____ day of _____,
_____ by and between _____ hereinafter known as the
“Customer” and Florida Public Utilities Company hereinafter know as the “Company”. This agreement is
made in accordance with Florida Public Commission Rule 25-6.065 F.A.C., Interconnection and Net
Metering of Customer-Owned Renewable Generation and under the terms and conditions as approved by
the Florida Public Service Commission pursuant to Rule 25-6.065(3), F.A.C.

1. The Customer’s renewable generation system is within the Company service territory and is
located at:

and should be installed and operational by:

_____, _____.

2. Customer will ensure the installation will meet or exceed all requirements noted below, will
provide the Company with reasonable notification prior to the operation of the system and will assist the
Company in verifying that the installation complies with the agreement prior to operating in parallel with
the Company’s electric system.

3. The Customer’s renewable generation system is described as follows:

- a. Equipment Manufacturers Name and Address:

- b. Manufacturers Reference Number, Serial Number, Type, Style, Model, Etc.

- c. Name Plate Rating (KW and Voltage):

*INTERCONNECTION AGREEMENT FOR CUSTOMER OWNED
TIER 3 RENEWABLE GENERATION SYSTEMS
(Greater than 100 KW and Less than or Equal to 2 MW)
(Continued)*

4. Standard Interconnection Agreement Requirements – To qualify for expedited interconnection as a Tier 3 generator pursuant to Rule 25-6.065, F.A.C., the Facility must:
 - (a) Comply with IEEE 1547 (2003) Standard for Interconnecting Distributed Resources with Electric Power Systems.
 - (b) Comply with IEEE 1547.1 (2005) Standard Conformance Test Procedures for Equipment Interconnecting Distributed Resources with Electric Power Systems.
 - (c) Comply with UL 1741 (2005) Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.
 - (d) Have a Gross Power Rating that does not exceed 90% of the Customer’s utility distribution service rating.
 - (e) Have a Gross Power Rating of greater than 100 KW and less than or equal to 2 MW.

5. Customer Qualifications and Fees – The Customer shall comply with the following to qualify as a Tier 3 generator pursuant to Rule 25-6.065, F.A.C.:
 - (a) Customer-owned renewable generation shall be considered certified for interconnected operation if it has been submitted by a manufacturer to a nationally recognized testing and certification laboratory, and has been tested and listed by the laboratory for continuous interactive operation with an electric distribution system in compliance with the applicable codes and standards listed in Section (4).
 - (b) Customer-owned renewable generation shall include a utility-interactive inverter, or other device certified pursuant to Section (5) (a) that performs the function of automatically isolating the Customer-owned generation equipment from the electric grid in the event the electric grid loses power.
 - (c) Should the Company determine that an interconnection study is necessary; a charge based on actual costs of the study will be the responsibility of the Customer. Prior to initiation of the study, \$2,000 (cost not to exceed \$2,000) will be paid by the Customer. Should actual study cost be less than \$2,000, the difference will be refunded to the Customer. Additionally, the Customer will be responsible for cost associated with any modifications to the Company’s system that is identified in the interconnection study.

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(Continuea)*

Any such charges shall not be assessed on the Customer without prior approval of the FPSC as per Rule 25-6.065(4) (h). This agreement will not be executed until the expansion or other work identified in the study has been completed and payment received.

- (d) Tier 3 Customers who request interconnection of Customer-owned renewable generation shall be charged a one-time non-refundable application fee of \$350.
6. Inspection Requirements – Prior to operating the Customer system in parallel with Company’s electric system, the Customer will:
- (a) Have the Customer-owned renewable generation inspected and approved by local code officials prior to its operation in parallel with the Company system to ensure compliance with applicable local codes.
 - (b) Make provisions that permit the Company to inspect Customer-owned renewable generation and its component equipment, and the documents necessary to ensure compliance with Sections (4) and (5). The Customer shall notify the Company at least 10 days prior to initially placing Customer equipment and protective apparatus in service and the Company shall have the right to have personnel present on the in-service date. If the Customer-owned renewable generation system is subsequently modified in order to increase its gross power rating, the Customer must notify the Company by submitting a new application specifying the modifications at least 30 days prior to making the modifications.
 - (c) Provide for protection of the renewable generating equipment, inverters, protective devices, and other system components from damage from the normal and abnormal conditions and operations that occur on the Company system in delivering and restoring power; and is responsible for ensuring that Customer-owned renewable generation equipment is inspected, maintained, and tested in accordance with the manufacturer’s instructions to ensure that it is operating correctly and safely.
7. Indemnity for Loss to Third Parties - The Customer shall hold harmless and indemnify the Company for all loss to third parties resulting from the operation of the Customer-owned renewable generation, except when the loss occurs due to the negligent actions of the Company. The Company shall hold harmless and indemnify the Customer for all loss to third parties resulting from the operation of the Company’s system, except when the loss occurs due to the negligent actions of the Customer.

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8. Customer Insurance Requirements – The Customer owning a Tier 3 generator is required by rule to obtain general liability insurance for personal and property damage in the amount of no less than two million dollars (\$2,000,000) as a result of the operation of the generator. Prior to parallel operation, the Customer shall provide initial proof of insurance or sufficient guarantee and proof of self-insurance, evidencing the generator. The Customer shall continue to provide proof of continuing insurance within 30 days of any policy renewal.
9. Manual Disconnect Switch – Customer’s operating a Tier 3 generator shall install, at the Customer’s expense, a manual disconnect switch of the visible load break type to provide a separation point between the AC power output of the Customer-owned renewable generation and any Customer wiring connected to the Company’s system. The manual disconnect switch shall be mounted separate from, but adjacent to, the meter socket and shall be readily accessible to the Company and capable of being locked in the open position with a single Company padlock.
10. Disconnection From Customer System - The Company may open the manual disconnect switch pursuant to the conditions set forth below in (10) (a) – (10) (d), isolating the Customer-owned renewable generation, without prior notice to the Customer. To the extent practicable, however, prior notice shall be given. If prior notice is not given, the Company shall at the time of disconnection leave a door hanger notifying the Customer that their Customer-owned renewable generation has been disconnected, including an explanation of the condition necessitating such action. The Company shall reconnect the Customer-owned renewable generation as soon as the condition necessitating disconnection is remedied.
- a. Emergencies or maintenance requirements on the Company’s electric system;
 - b. Hazardous conditions existing on the Company system due to the operation of the Customer’s generating or protective equipment as determined by the Company;
 - c. Adverse electrical effects, such as power quality problems, on the electrical equipment of the Company’s other electric consumers caused by the Customer-owned renewable generation as determined by the Company;
 - d. Failure of the Customer to maintain the required insurance coverage.

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(Continued)*

11. Administrative Requirements

- (a) The Company shall maintain on its website a downloadable application for interconnection of Customer-owned renewable generation, detailing the information necessary to execute the Standard Interconnection Agreement. Upon request the Company shall provide a hard copy of the application within 5 business days.
- (b) Within 10 business days of receipt of the Customer's application, the Company shall provide written notice that it has received all documents required by the Standard Interconnection Agreement or indicate how the application is deficient. Within 10 business days of receipt of a completed application, the Company shall provide written notice verifying receipt of the completed application. The written notice shall also include dates for any physical inspection of the Customer-owned renewable generation necessary for the Company to confirm compliance with Sections (4) through (10) and confirmation regarding the requirement of a Tier 3 interconnection study.
- (c) The Standard Interconnection Agreement shall be executed by the Company within 30 calendar days of receipt of a completed application. This will be extended to 90 calendar days if the Company determines that an interconnection study is required.
- (d) The Customer must execute the Standard Interconnection Agreement and return it to the Company at least 30 calendar days prior to beginning parallel operations and within one year after the utility executes the Agreement. All physical inspections must be completed by the Company within 30 calendar days of receipt of the Customer's executed Standard Interconnection Agreement. If the inspection is delayed at the Customer's request, the Customer shall contact the utility to reschedule an inspection. The Company shall reschedule the inspection within 10 business days of the Customer's request.

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12. Net Metering

- (a) The Company shall enable each Customer-owned renewable generation facility interconnected to the investor-owned utility's electrical grid pursuant to this rule to net meter.
- (b) The Company shall install, at no additional cost to the Customer, metering equipment at the point of delivery capable of measuring the difference between the electricity supplied to the Customer from the investor-owned utility and the electricity generated by the Customer and delivered to the investor-owned utility's electric grid.
- (c) Meter readings shall be taken monthly on the same cycle as required under the otherwise applicable rate schedule.
- (d) The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation in accordance with normal billing practices.
- (e) During any billing cycle, excess Customer-owned renewable generation delivered to the Company's electric grid shall be credited to the Customer's energy consumption for the next month's billing cycle.
- (f) Energy credits produced pursuant to Section (12) (e) shall accumulate and be used to offset the Customer's energy usage in subsequent months for a period of not more than twelve months. At the end of each calendar year, the Company shall pay the Customer for any unused energy credits at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (g) When a Customer leaves the system, that Customer's unused credits for excess kWh generated shall be paid to the Customer at an average annual rate based on the Company's COG-1, as-available energy tariff.
- (h) Regardless of whether excess energy is delivered to the Company's electric grid, the Customer shall continue to pay the applicable Customer charge and applicable demand charge (if applicable) for the maximum measured demand during the billing period. The Company shall charge for electricity used by the Customer in excess of the generation supplied by Customer-owned renewable generation at the Company's otherwise applicable rate schedule. The Customer may at their sole discretion choose to take service under the Company's standby or supplemental service rate, if available.

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13. Renewable Energy Certificates - Customers shall retain any Renewable Energy Certificates associated with the electricity produced by their Customer-owned renewable generation equipment. Any additional meters necessary for measuring the total renewable electricity generated for the purposes of receiving Renewable Energy Certificates shall be installed at the Customer's expense, unless otherwise determined during negotiations for the sale of the Customer's Renewable Energy Certificates to the Company.
14. Change of Ownership – This agreement shall not be assigned or transferred without prior written consent of the Company. Should there be a change in ownership; the Customer shall provide the Company with 30 day notice prior to the change. The Company will contact the new owner prior to the end of the 30 days in order to execute a new agreement. The new owner will not be entitled to operate the generator in parallel with the Company system or be net metered until a new agreement is executed by both parties. However, this agreement shall inure to the benefit of and binding upon the respective heirs, legal representatives, successors and assigns of the parties involved until a new agreement is executed.
15. No Extension of Credit – In executing this agreement, the Company does not, nor should it be construed to extend credit or financial support for the benefit of any third parties lending money to or having other transactions with the Customer or any assignee of this agreement.
16. Applicability of Tariff – The Company's tariff and associated technical terms and abbreviations, general rules, regulations and standard electric service requirements are incorporated herein by reference. In the event that this tariff and the Interconnection Agreement is revised due to rule changes approved by the Florida Public Service Commission, the Company and the Customer agree to replace this agreement with an amended agreement that complies with the amended Florida Public Service Commission rules.
17. Entire Agreement – This agreement supersedes all previous agreements or representations, either written or oral, heretofore in effect between the Company and the Customer, made in respect to matters herein contained, and when duly executed, this agreement constitutes the entire agreement between the parties.

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18. Termination – Upon termination of this agreement, the Company shall open and padlock the manual disconnect switch, if applicable, and remove any additional kilowatt-hour meter and associated Company equipment. At the Customer’s expense, the Customer agrees to permanently isolate the Facility from the Company’s electric service grid. The Customer shall notify the Company within ten (10) business days that the isolation procedure has been completed.
19. Retail Purchase of Electricity - “Customer-owned renewable generation” means an electric generating system located on a Customer’s premise that is primarily intended to offset part or all of the Customer’s electricity requirements with renewable energy. The term “Customer-owned renewable generation” does not preclude the Customer of record from contracting for the purchase, lease, operation, or maintenance of an on-site renewable generation system with a third-party under terms and conditions but does not include the retail purchase of electricity from the third party.
20. The Customer agrees to indemnify and hold harmless the Company, its subsidiaries or affiliates, and their respective employees, officers and directors, against any and all liability, loss, damage, cost or expense which the Company, it subsidiaries, affiliates, and their respective employees, officers and directors may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Customer under the obligations of this agreement. The Company agrees to indemnify and hold harmless the Customer, against any and all liability, loss, damage, cost or expense which the Customer may hereafter incur, suffer or be required to pay by reason of negligence on the part of the Company under the obligations of this agreement.
21. Communications, either emergency or routine, related to this agreement or operation of the installation shall be made to the following parties:

Company:

Customer:

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22. Dispute Resolution – The Company and Customer may seek resolution of disputes arising out of this interpretation of this agreement pursuant to Rule 25-22.032, F.A.C., Customer Complaints, or Rule 25-22.036, F.A.C., Initiation of Formal Proceedings.

IN WITNESS WHEREOF, the Customer and the Company execute this Agreement
this _____ day of _____, _____.

Title: _____

WITNESS:

FLORIDA PUBLIC UTILITIES COMPANY
COMPANY

By: _____

Title: _____

Date: _____

Date: _____

WITNESS:

CUSTOMER

By: _____

Title: _____

Date: _____

CONTRACTS AND AGREEMENTS

Container Corporation of America

Agreement dated December 15, 1992

ITT Rayonier, Inc., Fernandina Division

Agreement dated March 14, 2012