CITIZENS OF THE STATE OF FLORIDA, THROUGH THE FLORIDA OFFICE OF PUBLIC COUNSEL,	)	**IN THE FLORIDA PUBLIC SERVICE COMMISSION**
	)	**DOCKET NO. 20220069-GU**
Appellants,	)	
v.	)	
	)	**NOTICE OF ADMINISTRATIVE APPEAL**
FLORIDA PUBLIC SERVICE COMMISSION	)	
Appellee.	)	

NOTICE IS GIVEN that the Citizens of the State of Florida ("Citizens"), Appellants, through the Office of Public Counsel, appeal to the Supreme Court of the State of Florida the order of the Florida Public Service Commission, Order No. PSC-2023-0177-FOF-GU, rendered on June 9, 2023. A copy of Order No. PSC-2023-0177-FOF-GU is attached to this Notice of Administrative Appeal as Exhibit "A."

The nature of the order is that it is the Final Order Granting in Part and Denying in Part Florida City Gas' Petition for Certain Rate Increases.

Pursuant to Fla. R. App. P. 9.110(d), Citizens hereby inform the Court that Citizens filed a Motion for Reconsideration of Order No. PSC-2023-0177-FOF-GU with the Florida Public Service Commission on June 23, 2023, and that motion is pending.

Florida Office of Public Counsel

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CERTIFICATE OF SERVICE

DOCKET NO. 20220069-GU

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished by electronic mail on this 7th day of July 2023, to the following:

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CITIZENS OF THE STATE OF	**)**	
FLORIDA, THROUGH THE	**)**	**IN THE FLORIDA PUBLIC**
FLORIDA OFFICE OF PUBLIC	**)**	**SERVICECOMMISSION**
COUNSEL,	**)**	
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	)	**NOTICE OF**
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COMMISSION	**)**	**APPEAL**
	)	
Appellee.	**)**	
	)	

FLORIDA PUBLIC SERVICE COMMISSION
ORDER NO. PSC-2023-0177-FOF-GU, ISSUED JUNE 9, 2023

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for rate increase by Florida City Gas.	DOCKET NO. 20220069-GU ORDER NO. PSC-2023-0177-FOF-GU ISSUED: June 9, 2023

The following Commissioners participated in the disposition of this matter:

ANDREW GILES FAY, Chairman
MIKE LA ROSA
GABRIELLA PASSIDOMO

APPEARANCES:

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On behalf of Florida City Gas (FCG).

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Florida Public Service Commission General Counsel.

ORDER GRANTING IN PART AND DENYING IN PART
FLORIDA CITY GAS' PETITION FOR CERTAIN RATE INCREASES

BY THE COMMISSION:

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Background

On May 31, 2022, Florida City Gas (FCG or Company) filed a petition seeking the Florida Public Service Commission's (Commission) approval of a rate increase and associated depreciation rates based on a projected test year ending December 31, 2023. FCG is a natural gas local distribution company providing sales and transportation of natural gas, and is a public utility subject to this Commission's regulatory jurisdiction under Chapter 366, Florida Statutes (F.S.). As a subsidiary of Florida Power & Light Company (FPL), FCG currently serves approximately 116,000 residential, commercial, and industrial natural gas customers in Miami-Dade, Broward, St. Lucie, Indian River, Brevard, Palm Beach, Hendry, and Martin counties.

Specifically, FCG's request consists of: (a) an increase in base rates and charges sufficient to generate a total base revenue increase of $29.0 million based on a projected 2023 Test Year, which includes (i) an incremental base rate revenue requirement of $18.8 million, (ii) the revenue requirements for the previously approved Liquefied Natural Gas (LNG) Facility, and (iii) the reclassification of the Safety, Access, and Facility Enhancement (SAFE) program revenues from clause to base rates; (b) a 10.75 percent mid-point return on equity (ROE) and an equity ratio of 59.6 percent from investor sources for all regulatory purposes; (c) implementation of a reserve surplus amortization mechanism (RSAM), which is a critical and essential component of FCG's four-year rate plan; (d) approval of RSAM-adjusted depreciation rates, which is necessary to support the RSAM and decreases the incremental revenue requirement by $2.7 million; (e) the continuation of the Storm Damage Reserve provision approved as part of FCG's 2018 Settlement Agreement, as modified to reflect the Commission's new storm rule for gas utilities; (f) a mechanism that will allow FCG to adjust base rates in the event tax laws change during or after the conclusion of this proceeding; (g) continuation and expansion of the existing SAFE program, which will allow FCG to further improve safe and reliable service to customers and the communities it serves; and (h) implementation of a new limited advanced metering infrastructure pilot program (AMI Pilot) that will enable FCG to explore the potential for AMI meters to provide enhanced service to FCG's customers.

FCG initially requested an increase of $29.0 million in additional annual revenues, but reduced its request to $28.3 million. Of that amount, $5.7 million is associated with the reclassification of the Company's SAFE program revenues from surcharge to base rates and $3.8 million is related to the revenue requirements for the previously approved LNG Facility. Additionally, the remaining $18.8 million is necessary, according to FCG, for the Company to earn a fair return on its investment and to adopt the requested RSAM designed to manage earnings in order to mitigate the need for rate relief during the next four years. FCG based its request on a 13-month average rate base of $489 million for the projected test year ending December 31, 2023. The requested overall rate of return is 7.09 percent based on a mid-point of 10.75 percent return on equity.

The Company's last rate case was filed on October 23, 2017, and was resolved by the Commission's approval of a settlement agreement in 2018 (2018 Settlement Agreement).[1] The Commission-approved settlement agreement provided the opportunity for FCG to increase its base rates and charges to generate an additional $11.5 million in revenues for the projected test year ending December 31, 2018. The settlement agreement also authorized a return on equity of 10.19 percent.

We acknowledged intervention by the Office of Public Counsel (OPC), and intervention was granted to the Federal Executive Agencies (FEA) and to the Florida Industrial Power Users Group (FIPUG) (collectively "Intervenors"). In a previous order, we suspended the proposed permanent increase in rates and charges.

Three virtual and two in-person customer service hearings were held in September of 2022. A total of thirteen customers participated at the virtual service hearings and four customers spoke at the in-person service hearings, and all spoke favorably of FCG's quality of service, with some also expressing concerns regarding a rate increase. The Commission received letters from six customers that were placed in the docket. All of the customers urged the Commission not to increase their gas rates during these financially challenging times, and one customer commented on the poor customer service that they had experienced.

An administrative hearing was held December 12-13, 2022. At the hearing, we approved proposed stipulations on a number of issues, as reflected herein. The parties filed post-hearing briefs which argued their positions on the issues litigated at the administrative hearing. After the parties filed their briefs, we held Special Agenda Conferences on March 28 and April 25, 2023 to address those issues.

The Commission has jurisdiction over this matter pursuant to Chapter 366, F.S., including Sections 366.041, 366.06, and 366.071, F.S.

Decision

I. Rate Plan Duration

A. Four-year Rate Plan

1. Parties' Arguments

FCG argued that its requested four-year rate plan would provide rate stability and benefits to customers that would not be available with a single-year rate plan. FCG argued that disapproval of the Company's proposed four-year rate plan would cost customers more. Additionally, FCG argued that if we approved the four-year plan, our final Order would be both binding and enforceable against all parties to this docket, and thus FCG would be obligated to comply with the requirements and limitations of the four-year plan.

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[1] Order No. PSC-2018-0190-FOF-GU, issued April 20, 2018, in Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City Gas.*

OPC argued that, absent a settlement agreement, this Commission does not have authority or precedent for approving a provision requiring a utility to "stay out" of base rate proceedings before this Commission for a set period of time; therefore, it should not approve FCG's requested four-year rate plan. OPC argued that absent a settlement agreement, this Commission must review each request and determine whether it will result in fair, just, and reasonable rates.

OPC also argued that we would have no enforceable way to prevent FCG from requesting a new rate case before the "stay-out" period ended. OPC cited Order No. PSC-2021-0446-S-EI, where a "stay-out" provision was an issue in the proceeding; however, the case was ultimately resolved with a settlement agreement and a ruling by this Commission on the propriety of the provision was never made. OPC also argued that when questioned at the hearing, FCG appeared to waver in its commitment not to request another rate increase for four years, specifically given factors such as inflationary pressures. FIPUG adopted the position of OPC.

2. <u>Analysis</u>

Although a significant portion of FCG's rate plan was FCG's stated commitment to not request another general base rate increase effective prior to January 1, 2027, FCG acknowledged that, if the rate plan was approved, this Commission would have full regulatory oversight of rates and charges and the Company would continue to provide earnings surveillance reports as required. We agree with OPC that regardless of any assurances to the contrary, FCG cannot guarantee it would not seek a base rate increase before 2026. To ensure fair, just, and reasonable rates are charged, section 366.06(2), F.S., provides that if a utility's rates are insufficient to yield reasonable compensation, it may request a proceeding in order for the Commission to determine just and reasonable rates. On the other hand, if we find that rates are excessive, the Commission can initiate a proceeding upon a request from an affected person or on its own motion to determine just and reasonable rates.

3. <u>Conclusion</u>

Section 366.06(2), F.S., states that if a utility's rates are insufficient to yield reasonable compensation it may request a proceeding in order for the Commission to determine just and reasonable rates. Likewise, if we find that rates are excessive, we can initiate a proceeding to determine just and reasonable rates. Accordingly, while we have resolved base rate cases in previous years that include multi-year increases to rates, and in settlement agreements we have approved "stay-out" provisions, we continue to recognize our obligation to monitor utility earnings and, if circumstances warrant, require additional proceedings. For these reasons, we acknowledge FCG's commitment while also noting that approval of FCG's plan, either in part or its entirety, would not prohibit future proceedings on these matters over the next four years. Thus, this Order addresses whether there is record evidence to support the other elements of FCG's proposal, including the single incremental base revenue increase, requested ROE and equity ratio, cost of service, an RSAM, the SAFE program, the AMI Pilot program, potential tax law changes, and the Storm Damage Reserve.

II. Test Period and Forecasting

A. Projected Test Year

1. Parties' Arguments

FCG witness Campbell argued that the 2023 projected test year used by the Company, based on the 12-month period ending December 31, 2023, best reflects the Company's revenues, costs, and investments during the year in which new rates are proposed to go into effect. The Company also proposed that new base rates become effective February 1, 2023, at a level "sufficient to recover the Company's revenue requirements in 2023 with an opportunity to earn a fair and reasonable return."

OPC argued in its brief that FCG failed to meet the burden of demonstrating that the projected 2023 test year is appropriate as the Company has refused to demonstrate that there will be no merger activities that will affect the appropriateness of the test period. OPC further argued that its concerns about potential merger or sale activities are not merely "idle speculation," citing the acquisition of FCG by NextEra Energy from Southern Company during the Company's 2017 rate case. OPC continued that this acquisition was done during the 2017 rate case "without informing the Commission or parties to the case and settlement." OPC stated that, although FCG witnesses Campbell and Fuentes have each denied that there are ongoing merger or sale activities that would affect rates, "neither witness could unequivocally state that they would be in a position to know under all circumstances."

2. Analysis

In general, a projected test year methodology uses forecasted data for a 12-month period to match average revenues and expenses with average rate base investment. OPC and FIPUG agree that the 2023 test year may be representative of the period of time in which rates will be in effect, with the caveat of "with appropriate adjustments" and "no imminent merger or sale activities." However, OPC argued that the Company did not adequately demonstrate there will be no merger activities that will affect the appropriateness of the test year, and therefore, the test period ending December 31, 2023 is not appropriate for setting rates. FCG argued that the Intervenors' concerns about potential merger activities are unsupported by the record and should be rejected, as there is "no evidence of any merger or sale activity, costs, or savings included in FCG's 2023 Test Year."

3. Conclusion

We find that denying the use of a projected test year based solely upon the possibility of merger activities, as argued by the Intervenors, is not reasonable. With regard to the Intervenors' assertion that "appropriate adjustments" be made to the 2023 test year, no Intervenors cited any specific adjustments or alternatives to the 2023 test year relating to this issue.

We find that FCG's proposed 2023 test year will result in a matching of the Company's revenues to be produced, during the first twelve months in which the new rates would be in effect, with average rate base investment and average expenses for the same period. Therefore, we find the projected test period of the twelve months ending December 31, 2023, is appropriate.

B. Customer and Therm Forecasts

1. Parties' Arguments

FCG witness Campbell testified that the Company's customer and therm forecasts were developed using statistically sound econometric and regression models and included logically reasonable drivers obtained from leading industry experts. Witness Campbell further stated that the Company's customer and therm forecasts were evaluated for reasonableness by comparing forecasted trends against historical trends and other growth factors. Witness Campbell argued that the forecasting approach used in this case is consistent with the criteria used by the Commission in previous proceedings.[2]

OPC argued that adjustments should be made with regard to the Company's customer and therm forecasts, while noting that the forecasts typically become less reliable the further they are projected into the future.

2. Analysis

In this case, FCG provided forecast models that detail the Company's historical and forecasted customer counts and therm sales. FCG witness Campbell stated that the Company's customer forecasts reflect the total number of active accounts served by FCG and include factors such as estimates of new service installations and changes in the number of inactive accounts, while the Company's therm sales reflect the amount of natural gas provided to all customers served by FCG. The Company projected a customer count of approximately 117,487 and therm sales of approximately 173,612,198 for the 2023 test year. The Intervenors did not present testimony or evidence to disprove FCG's test year forecast models or assumptions, and did not propose any adjustments to FCG's forecasts of customers and therms for the projected test year.

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[2] In its brief, FCG cited: Order No. PSC-16-0032-FOF-EI, issued January 19, 2016, in Docket No. 20150196-EI, *In re*: *Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company*; Order No. PSC-14-0590-FOF-EI, issued October 21, 2014, in Docket No. 20140111-EI, *In re: Petition for determination of cost effective generation alternative to meet need prior to 2018, by Duke Energy Florida, Inc.*; Order No. PSC-13-0505-PAA-EI, issued October 28, 2013, in Docket No. 20130198-EI, *In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company*; Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 20110138-EI, *In re*: *Petition for increase in rates by Gulf Power Company*; Order No. PSC-12-0187-FOF-EI, issued April 9, 2012, in Docket No. 20110309-EI, *In re: Petition to determine need for modernization of Port Everglades Plant, by Florida Power and Light Company*; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 20080366-GU, *In re: Petition for rate increase by Florida Public Utilities Company.*; Order No. PSC-04-0128-PAA-GU, issued February 9, 2004, in Docket No. 20030569-GU, *In re: Application for rate increase by City Gas Company of Florida.*

3. Conclusion

Based on an analysis of FCG's historical customer and usage data (2010-2021), year-to-date accuracy (2022), and year-over-year growth rates, we find the forecast models and assumptions utilized by FCG provide a reasonable estimate of the Company's customer counts and therm sales, by rate class, for the 2023 test year. Therefore, we find the Company's customer and therm sales forecasts for the projected test year are reasonable and appropriate, and no adjustments are necessary.

C. Estimated Gas Revenues

1. Parties' Arguments

We next address whether FCG's estimated revenues from sales of gas by rate class at present rates for the projected test year are appropriate. FCG argued that the same reasonable forecasting methodologies described in section II above were applied in developing its estimated revenues from sales of gas. The Company stated that these methodologies included statistically sound models and logically reasonable drivers obtained from leading industry experts. FCG argued that the record supports finding that the Company's projected revenues from the sale of gas by rate class have been "calculated based upon reliable, robust, and accepted methods."

OPC noted that witness Campbell stated both that he did not forecast the impact of potential growth in customers on 2024 and 2025 revenues, but he estimated that this growth would result in approximately $200,000 in additional revenues per year. OPC also noted that witness Campbell said that the Company's customer and therm forecasts typically become progressively less reliable the further they are projected into the future.

2. Analysis

FCG provided forecast models which detail the Company's forecasted customer counts and therm sales for the 2023 test year. Once FCG established these forecasts for the projected test year, the Company multiplied them by current rates for each customer class and combined those results to yield total revenues. The Company forecasted a total of $62,828,352 in revenues from sales of gas at present rates for the 2023 test year.

There was an exception to the Company's revenue forecast process for one customer class - Load Enhancement Service (LES). As detailed in MFR E-1, page 2 of 3, the forecasted revenues include a positive adjustment in the amount of $155,495 to reflect revenues associated with the LES rate class. FCG witness Debose testified that the LES customer class is an existing optional rate available to customers who can provide "verifiable documentation showing a viable alternative fuel or the opportunity to completely bypass FCG's system." In an effort to retain these customers on FCG's system, the Company's LES customers are eligible for a discounted, negotiated rate. The discount is recovered from the general body of ratepayers through the Competitive Rate Adjustment (CRA) rider. The Company explained that for the purposes of the revenue forecast, the LES customers were forecast at one hundred percent of their otherwise applicable rate schedules. FCG argued that this approach "better aligns the revenues and costs incurred to provide service to the LES customers with the appropriate rate schedule, while recognizing that the difference between the revenues under the tariffed rate and the negotiated LES rate are recovered through the CRA." We find this approach is reasonable for the purposes of estimating test year revenues for LES customers.

3. Conclusion

We have confirmed that FCG used the correct current rates and billing determinants consistent with the Company's forecasts for all customer classes in their calculations of test year revenue. We find that in all instances the revenue forecasts for all customer classes are reasonable. Furthermore, we note that the Intervenors did not present testimony or evidence to rebut FCG's test year forecast of revenues from sales of gas at current rates.

Thus, we find that FCG's estimated revenues from sales of gas by rate class at present rates for the projected test year, totaling $62,828,352, are reasonable and appropriate. This amount includes the Company-noted adjustment of $155,495 to reflect additional revenues associated with the Load Enhancement Service rate class.

III. Quality of Service

A. Quality of Service

1. Parties' Arguments

FCG argued that it provides safe, reliable, and high-quality service to customers and the communities it serves. The Company argued that none of the customers that participated at the service hearings expressed any negative views of FCG, and were instead complimentary of the Company and its employees. FCG asserted that it has taken steps since its last rate case to implement customer experiences and process improvements.

OPC noted that at least one customer submitted a comment expressing dissatisfaction with the quality of service provided by FCG.

2. Analysis

Pursuant to Section 366.041, F.S., in fixing rates the Commission is authorized to give consideration, among other things, to the efficiency, sufficiency, and adequacy of the facilities provided and the services rendered. Pursuant to Rule 25-7.018, Florida Administrative Code (F.A.C.), each utility must keep a complete record of all interruptions affecting the lesser of 10 percent or 500 or more of its division meters. Based on FCG's filing, there were no customer interruptions affecting either 10 percent or 500 meters during the historic test year.

The Commission held three virtual service hearings on September 14 and 15, 2022, as well as two in-person service hearings within FCG's service territory on September 20 and 21,

2022. These hearings provided an opportunity for FCG's approximately 116,000 customers to raise concerns regarding the Company's quality of service and its request for a rate increase. A total of thirteen customers participated at the virtual service hearings, all of whom spoke positively of the Company's quality of service, although one customer also voiced opposition to the rate increase. Four customers spoke at the in-person service hearings, and all spoke favorably of FCG's quality of service, while one customer also expressed concerns regarding the size of the rate increase.

We also examined the complaints presented in staff witness Calhoun's testimony and observed that the number of service complaints has continually decreased since 2018. Staff witness Calhoun testified that, from July 1, 2017, to June 30, 2022, 584 complaints were logged with the Commission with 489 of those being transferred to FCG. Of the complaints, approximately 52 percent concerned billing issues and approximately 48 percent involved quality of service issues. Additionally, witness Calhoun testified that four billing complaints and one service quality complaint appeared to demonstrate a violation of Commission Rules.

FCG witness Howard testified that the customer comments made at the service hearings were complimentary of the Company and the large majority of the customer contacts received by the Commission were informational in nature. Only 87 of the customer contacts were logged as complaints, with 4 being possible rule violations. Witness Howard testified that efforts had been made since 2018 to update the customer complaint resolution process. These efforts included: (1) creating a process to handle more complex questions from customers that cannot be adequately answered on the initial call; (2) cataloguing and addressing common complaints expressed by customers; (3) identifying and incorporating best practices from FPL's customer complaint process; (4) implementing a management review process for Commission complaints; (5) instituting a one-call resolution target for Warm-Transfers; and (6) establishing internal goals to reduce complaints. None of the intervenors took issue with FCG's quality of service.

3. Conclusion

Based on a review of all witness and customer testimony, we find that the Company's quality of service is adequate.

IV. Depreciation

A. Depreciation Parameters

Depreciation rates are calculated using parameters which include the Average Service Life (ASL), curve shape, the remaining life (in years), net salvage percentage, and reserve percentage. In order to arrive at the appropriate resulting depreciation rates, each parameter plays a part in the calculation.

In the development of depreciation rates, the first parameter reviewed is the ASL, which denotes the average number of years that the asset is expected to be in-service. While the ASL may be based, at least in part, on historical data, it is prospective in its outlook and implementation. Iowa curves are used to determine the remaining life of a particular type of asset by graphically representing the retirement patterns of utility assets. These are well-established depreciation tools. Each curve is denoted by a letter that defines when retirements are more likely to occur. An L curve implies that retirements tend to occur prior to the ASL, while an R curve implies that retirements tend to occur after the ASL.

The next parameter is the average remaining life, which is the average number of in-service years left for plant currently in service. FCG presented evidence that "service life estimates in any given depreciation study are, by their nature, estimates of what is expected to occur in the future based on information available at the time of the study." The third parameter for determining depreciation rates, net salvage, is gross salvage minus cost of removal. Net salvage is based on historical data but is also prospective in outlook. The last parameter needed for calculating depreciation rates is the reserve percentage which represents the portion of the investment accumulated through depreciation expense to date. The reserve percentage is calculated by dividing the book reserve by the original cost of plant.

Three proposals were put forward to calculate depreciation rates for each distribution and general plant account: FCG's traditional 2022 Depreciation Study (2022 Study), OPC's adjustments to FCG's 2022 Study, and FCG's Reserve Surplus Amortization Mechanism (RSAM) adjusted parameters. Each scenario proposed slightly different estimates for service lives and other depreciation parameters across various accounts.

1. Parties' Arguments

While FCG performed a traditional depreciation study as presented by Witness Allis, the Company also advocated for the use of its RSAM-adjusted parameters. FCG argued that the RSAM-adjusted parameters are the appropriate ones to use in conjunction with FCG's proposed RSAM because they are reasonable and they are the same as those approved through a settlement agreement in Peoples Gas System's most recent base rate case, with the exception of FCG's LNG Facility. Furthermore, FCG argued that the RSAM-adjusted parameters are very similar to the ones OPC witness Garrett has proposed in this and similar cases.

OPC argued in favor of its own method of calculating depreciation rates, stating that OPC witness Garrett developed his recommended depreciation rates using "the straight-line method, the average life procedure, the remaining life technique, and the broad group model." OPC witness Garrett used FCG's aged property data to develop an "observed life table" (OLT), which was then compared to survivor curves.

OPC asserted that if all of witness Garrett's proposed depreciation adjustments were applied to the 2022 Study, projected test year depreciation expense would be reduced by $1,543,130 and projected test year accumulated depreciation would be reduced by $771,565 when compared to witness Allis' 2022 Study parameters. OPC argued the adjustments to FCG witness Allis' depreciation parameters, as offered by witness Garrett, should be adopted in this case, and that the remaining life technique should be used to address any resulting reserve imbalance. OPC also opposed FCG's use of the RSAM-adjusted parameters, arguing the Commission lacked the authority to implement the RSAM outside of a settlement agreement.

2. Analysis

FCG presented testimony that both the traditional 2022 depreciation study and the RSAM adjusted parameters fell within a "range of reasonableness" when compared to the depreciation studies of other gas utilities. There was also testimony that the traditional 2022 Study parameters and OPC's proposed depreciation parameters would not result in a large enough reserve for the RSAM to function properly.

FCG also offered testimony that depreciation parameters are only estimates of what may occur in the future and therefore it is inevitable that those estimates will result in surpluses and deficits, and thus the RSAM parameters were reasonable. FCG asserted the Commission's depreciation rule, which requires gas utilities to file a depreciation study every five years, recognizes and accounts for this variability. In support of its RSAM, FCG also offered evidence that the National Association of Regulatory Utility Commissioners (NARUC) states that the true depreciation parameters only become known "after the plant has lived its entire useful life."[3]

Additionally, FCG asserted the RSAM-adjusted depreciation parameters are a reasonable alternative given that they are based on a similar utility in the same geographic location with similar assets. FCG witness Campbell stated that the assets and facilities on FCG's system are similar to the assets used by Peoples Gas System, and are located in similar geographic regions, making the RSAM parameters a reasonable alternative to the depreciation study. Witness Campbell further testified that the RSAM-adjusted parameters themselves are similar to those offered by OPC witness Garrett in this case, arguing this further supports their reasonableness.

3. Conclusion

FCG witness Campbell presented credible testimony and we find the appropriate depreciation parameters in this case are the RSAM-adjusted parameters proposed by FCG. Accordingly, we find that the appropriate depreciation parameters and resulting depreciation rates for each distribution and general plant account are those shown on Table 1 below. As a result, the appropriate amount of Depreciation and Amortization Expense for the projected test year is $17,316,573. The resulting reserve imbalance is discussed more fully in the next section.

[3] National Association of Regulatory Commissioners Public Utility Depreciation Practices, p. 189

Table 1
Depreciation Parameters

Account Number	Account Title	Curve Type	Average Service Life (yrs)	Average Remaining Life (yrs)	Reserve (%)	Future Net Salvage (%)	Remaining Life Rate (%)
DISTRIBUTION PLANT							
375	Structures & Improvements	L0	33	31.00	9.07	0	3.8
376.1	Mains - Steel	R1.5	65	50.32	51.42	(50)	2.0
376.2	Mains - Plastic	R2	75	65.88	28.33	(33)	1.6
378	Measuring & Regulating Equip. - General	R1.5	40	36.88	13.64	(10)	2.6
379	Measuring & Regulating Equip. - City Gate	R2.5	50	40.64	28.40	(10)	2.0
380.1	Services - Steel	R0.5	52	32.15	89.49	(125)	2.5
380.2	Services - Plastic	R1.5	55	46.56	25.68	(68)	3.1
381	Meter	R2	19	12.43	30.11	3	6.9
381.1	Meters - ERT	R2	19	14.42	21.22	3	9.7
382	Meter Installations	R1	44	34.95	28.53	(25)	3.6
382.1	Meter Installations - ERT	R1	44	36.23	33.08	(25)	10.3
383	House Regulators	S1	42	33.08	24.92	0	2.3
384	House Regulators Installations	R1	47	34.93	5.16	(25)	3.4
385	Industrial Measuring & Reg. Station Equip	R3	37	17.79	60.92	(2)	2.3
387	OTHER EQUIPMENT	L2	24	18.05	20.34	0	4.4
GENERAL PLANT							
390	Structures & Improvements	L0	25	20.23	18.27	0	4
392	Transportation Equipment	L2	12	4.66	33.68	4	13.4
392.1	Transportation Equip. - Auto & Light Trucks	L2.5	9	4.19	63.75	11	6.0
392.2	Transportation Equip. - Service Trucks	L3	10	6.05	49.13	11	6.6
392.3	Transportation Equip. - Heavy Trucks	L2	12	6.53	45.8	4	7.7
394.1	Natural Gas Vehicle Equipment	S4	20	13.5	60.18	0	3.0

B. Resulting Reserve Imbalances

1. Parties' Arguments

FCG argued that the appropriate reserve imbalance based on the RSAM-adjusted depreciation rates would be $52.1 million. FCG explained that, under the RSAM scenario, $25 million would be available for the Company to amortize during the 2023-2026 timeframe. FCG contended that even with the $25 million Reserve Amount, FCG would still have to find cost savings to reach the proposed midpoint ROE.

OPC witness Garrett testified that when a reserve imbalance exists, the remaining life technique should be used to address the imbalance over the remaining life of the assets.

2. Analysis and Conclusion

The formula for the Theoretical Reserve, Book Investment – Future Accruals – Future Net Salvage, is provided in Rule 25-7.045(4)(k), F.A.C. FCG witness Allis also calculated a $50.8 million theoretical reserve surplus for FCG's distribution accounts and a $1.3 million reserve surplus related to its general plant accounts, based on FCG witness Fuentes' proposed RSAM life and salvage parameters. We agree with witness Allis' calculations. Using this formula and the values for the life and salvage components that we found above, we calculate a total reserve imbalance of $52,126,500, comprised of $50,813,200 in the Distribution account and $1,313,300 in the General account.

C. Corrective Depreciation Measures - RSAM

1. Parties' Arguments

Because the approval of the RSAM parameters will result in a reserve imbalance, we next address what corrective measures should be taken with regard to that reserve imbalance. FCG asserted that its proposed RSAM is an appropriate and critical component of FCG's proposed rate plan and in conjunction with the other components of the plan, the RSAM will enable FCG to avoid increasing base rates through at least the end of 2026. According to FCG, the expected benefits resulting from the RSAM will provide significant customer benefits and savings including a lower annual revenue requirement, avoiding repetitive and costly rate proceedings, providing customers with rate stability and certainty, and enabling FCG to focus on providing safe, reliable, and affordable service to its customers.

Additionally FCG asserted that without the RSAM, it would fall below its proposed ROE range and would need to file an additional rate case in 2024 for a base rate increase in 2025. According to FCG, its RSAM-adjusted depreciation rates are based on the depreciation parameters recently agreed to and approved in the PGS base rate case in Docket No. 20200051-GU and therefore they represent a reasonable alternative to those contained in FCG's 2022 Depreciation Study. FCG argued that these RSAM-adjusted depreciation parameters are within the range of reasonableness, and are in line with those approved for other similar natural gas utilities in Florida. FCG asserted that the evidence supports a finding that FCG's proposed RSAM is fair, just, and reasonable and should therefore be approved.

OPC argued that use of the RSAM, absent a settlement, is inconsistent with both Rule 25-7.045, F.A.C., and the statutory requirement to set just and reasonable rates set forth in Chapter 366, F.S. OPC asserted that absent a stipulation of the parties, the Commission lacks the authority to approve an RSAM mechanism that can be utilized in conjunction with the surplus or Reserve Amount. OPC also argued that the proposed RSAM could be used to enhance shareholder earnings and maintain FCG's earnings at the top of the authorized range, and asserted it would limit the Commission's and other parties' ability to review FCG's rates in the future by creating a self-regulating mechanism.

FEA also opposed the RSAM and reiterated OPC's arguments that the proposed RSAM would be used to respond to changes in underlying revenues and expenses in order to maintain a set ROE. FEA argued that FCG's proposed RSAM improperly shifts the risk of revenue recovery to customers, and allows FCG to adjust its depreciation expense leading to an artificially inflated rate base by distorting the accurate measurement of assets.

FEA witness Collins also testified the proposed RSAM would lead to potential future costs to FCG customers and would be used to increase the Company's earnings and its return. FIPUG joined the arguments of FEA.

2. Analysis

We recognize that our approval of the RSAM depreciation parameters above will result in a reserve imbalance, which we will address here. Before we do so, we first acknowledge that OPC raised the issue of our statutory authority to approve an RSAM.

We disagree with OPC that the Commission lacks authority to approve accounting mechanisms like the proposed RSAM unless it does so in a settlement agreement. Chapter 366, F.S., sets forth the Commission's jurisdiction and authority to fix fair, just, and reasonable rates. The Commission's jurisdiction and authority to fix fair, just, and reasonable rates pursuant to Chapter 366, F.S., are not conditioned upon whether the case is litigated or settled.

While the standard of review differs in a settlement versus a litigated rate case, it does not change the Commission's statutory authority or jurisdiction. In other words, a settlement, which operates under the public interest standard, cannot legally grant or change the Commission's jurisdiction and authority; only the legislature can do that. To hold that the Commission can only approve an RSAM in a settlement but not in a litigated proceeding would mean that the parties to a settlement can somehow circumvent or expand the Commission's legal jurisdiction and authority beyond what is granted by Chapter 366, F.S.

We also recognize that there was competing testimony about whether the RSAM should be approved in this case and whether it will benefit customers. We are persuaded by the testimony that the RSAM would allow FCG to manage its day-to-day fluctuations as well as take on the risk of both actual current as well as potential future increases in interest rates and inflation. FCG proposes having a Reserve Surplus amount of $25 million available for managing these daily fluctuations in revenues and expenses, but FCG did not propose any treatment for the remaining reserve surplus of $27.1 million. Therefore, that remaining surplus would remain on FCG's books and records until the Company files its next depreciation study.

While there was testimony offered that the RSAM would shift risk to customers, FCG offered evidence that its rate plan with the RSAM would result in fair, just, and reasonable rates. By approving the proposed RSAM, we believe FCG is in the best position to maintain its ROE within the approved range and thus reduce the likelihood of additional rate increases in the near future. As we expressed at our Agenda Conference on April 25, 2023, we are mindful of today's economy and the effects of inflation on customers and their utility bills. FCG offered testimony that adopting the proposal allows FCG to manage typical day-to-day fluctuations associated with running a utility business, while also having to absorb potentially higher costs resulting from inflation and rising interest rates. FCG also offered testimony that the use of the RSAM reduces the average residential bill by approximately $0.94 per month, the average commercial and industrial bill by approximately $5.15 per month, and the average GS-1 bill by approximately $465.83 per month.

FCG's evidence showed the RSAM will provide customer benefits including rate stability and certainty. There was also FCG testimony that by avoiding repetitive and costly rate proceedings, its rate proposal will save customers an approximate additional $2.0 million in rate case expense while still enabling the company to meet the natural gas needs of existing and new customers while continuing to provide safe, reliable, and high-quality customer service.

3. Conclusion

We have the authority to approve an RSAM and accordingly approve FCG's proposed use of the RSAM along with its Reserve Surplus of $25 million. We find the RSAM will result in a reduction of revenue requirement, save customers money on their utility bills, and give FCG the ability to manage its day-to-day business fluctuations, and allow FCG to take on the risk of increases in interest rates and inflation. FCG did not propose any treatment for the remaining reserve surplus of $27.1 million. Therefore, we find that the remaining surplus shall remain on FCG's books and records until the Company files its next depreciation study.

D. Implementation Date for Revised Depreciation Rates

1. Parties' Arguments

FCG witness Fuentes argued the implementation date for revised depreciation rates should be the effective date of the new base rates. FCG argued that this will be a matching of the new base rates with the new depreciation rates. FCG further argued that, without approval by the Commission for retroactive implementation, the implementation date for new depreciation rates should precede the Order approving such depreciation rates. OPC argued the revised rates should be effective January 1, 2023.

2. Analysis

Rule 25-7.045(4)(d), F.A.C., requires that the data submitted in a depreciation study, including plant and reserve balances or Company estimates, "shall be brought to the effective date of the proposed rates." Our staff confirmed that the plant and reserve balances were as of December 31, 2022, thus matching an implementation date of January 1, 2023. Furthermore, the Projected Test Year MFRs in this case were based on the period January 1, 2023, through December 31, 2023. FCG stated that the company filed its 2022 Study, along with the alternative RSAM-adjusted depreciation rates, direct testimony, and MFRs in compliance with Rule 25-7.045, F.A.C.

3. Conclusion

FCG provided depreciation study data extending through December 31, 2022 and did not provide study data for the month of January 2023. Therefore, in order to comport with Rule 25-7.045(4)(d), F.A.C., (the Depreciation Rule), the implementation date of the new depreciation rates and amortization schedules shall be January 1, 2023, not February 1, 2023.

V. Rate Base

A. Adjustments to Reflect SAFE Investments

There is no dispute about the adjustments to properly reflect SAFE investments. At hearing, we approved a stipulation whereby all parties agreed that $5.7 million of SAFE revenue requirements were appropriately transferred from clause recovery to base rates in the 2023 Test Year as required per our previous order.[4]

B. Advanced Metering Infrastructure (AMI) Pilot

1. Parties' Arguments

FCG is requesting a research and development pilot to evaluate Advanced Metering Infrastructure (AMI) with two-way communication capability. FCG attested that its proposed AMI Pilot will provide information on the potential benefits of deploying AMI with two-way communications system-wide. FCG argued that under the AMI Pilot, it will gather information on the benefits of automated remote readings, and the corrosion resistance and life of the 5,000 new smart meters to be installed under the pilot. FCG argues this is an appropriate sample size to determine benefits for the whole system while potentially reducing the costs.

OPC argued that the Commission should not approve FCG's proposed AMI Pilot because the benefits to customers are unknown, and because FCG did not attempt to estimate potential customer savings. In addition, OPC contended that FCG admitted that AMI technology has only been deployed by a small number of gas utilities in the country, and not at all in Florida. OPC asserted that by including this program in its rate request without any estimation of potential savings, FCG is attempting to recover costs for this program from customers imprudently. Therefore, OPC recommended that the Commission deny the AMI Pilot because FCG has not demonstrated the prudence of this program.

2. Analysis

Pilot programs are typically vehicles through which utilities explore new technologies or processes so they can assess the benefits using a sample prior to system-wide implementation. In this case, FCG is planning to replace 5,000 meters under the AMI Pilot, which would provide a large enough sample to test the benefits of smart meters with AMI technology on FCG's system without creating excessive costs, as this represents less than five percent of FCG's customer meters.

FCG argued in its brief that, as part of the pilot, FCG would collect data on the durability of the proposed smart meters, especially with regard to corrosion, and usage of two-way communications for central control of meter functions, such as remote connects and disconnects, and improved customer information on usage. The proposed pilot would be over a four-year period, with one year of installation and three years of operation, and consist of 5,000 smart

[4] Order No. PSC-15-0390-TRF-GU in Docket No. 150116-GU.

devices with related back-office technology support installed in the Brevard County area, where accelerated corrosion has been documented. After the conclusion of the pilot, FCG indicated in discovery it anticipates being able to report a summary of the findings, and provide sample reports with relevant information to the Commission. The estimated total cost of the AMI Pilot is $3.4 million in capital expenditures, with annual O&M expense estimated at $16,896, as corrected by FCG witness Howard. We find an adjustment of ($3,104) shall be made to the originally projected O&M expense for the AMI Pilot to reflect the corrected O&M expense identified in FCG witness Howard's testimony.

The Intervenors do not oppose the AMI Pilot, only its cost recovery, with OPC contending that the technology is both too new and intended to benefit shareholders, not customers. However, FCG maintained that the smart meters and AMI to be deployed are similar to the widely understood AMI technology that is used by electric utilities, and a small number of other gas utilities across the nation.

OPC witness Schultz raised concerns due to the newness of the technology to the gas industry, and because FCG did not include estimated benefits in the filing, only the proposed costs. Witness Schultz therefore argued that the Commission should disallow the recovery of expenses for the pilot, which he suggested should be borne by the shareholders, as they may benefit from a potential sale of the Utility.

Regarding the newness of the technology, FCG did not dispute that AMI technology, while common in the electric industry, has only been deployed by a limited number of gas utilities in the country, and not by any gas utilities in Florida. However, FCG witness Howard testified to the expected benefits associated with the AMI Pilot, which accrue to customers and the system itself, not shareholders, through improved functionality and potential cost reductions. In addition, FCG provided testimony that pilot projects enable a utility to test new technologies on a limited basis to determine if it would be beneficial to deploy these technologies system-wide, which is why FCG is proposing an AMI Pilot.

We are persuaded by FCG's testimony. We find that the newness of AMI technology to the gas industry, specifically in Florida, lends credibility to FCG's proposal for a pilot program to allow this technology to be further evaluated prior to full scale implementation. Denying pilot programs with expected customer benefits and reasonable costs would discourage utilities from proposing pilot programs for the Commission's consideration and negate opportunities for utilities to evaluate technologies that can enhance the service to and benefits for customers.

Regarding OPC's concern that FCG has not attempted to quantify benefits, the Utility has proposed the collection of data to quantify benefits through tasks such as remote meter reading, disconnection, and leak/outage detection, all of which should reduce related expenses. In addition, FCG indicated in discovery that after the conclusion of the pilot it anticipates being able to report a summary of the findings with regard to the project cost, meter installation, maintenance, and corrosion performance, and to provide sample reports including information such as customer daily usage, remote meter communication performance, and billing accuracy impacts.

3. Conclusion

Because FCG intends to gather information to determine the feasibility of AMI technology on its system and the appropriateness of system-wide deployment of this technology in the future, we find its potential to result in cost savings for the customers to be credible. For these reasons, we hereby approve the AMI Pilot. An adjustment of ($3,104) shall be made to the originally projected O&M expense provided for the AMI Pilot to reflect the corrected O&M expense identified in FCG witness Howard's revised testimony. In addition, we order FCG to provide a final report with a summary of the findings described above to the Commission within 90 days of completion of the AMI Pilot.

C. Plant in Service for Liquefied Natural Gas (LNG) Facility

1. Parties' Arguments

FCG contended that OPC waived its argument against the Liquefied Natural Gas (LNG) facility when OPC signed off on the 2018 Settlement Agreement. That agreement included provisions on both the need for and construction of the facility. FCG asserted that the Parties were aware that both the in-service date and costs were estimates, and that the terms of the agreement specifically envisioned some of this uncertainty, with rates going into effect at the in-service date of the unit.

Although the 2018 agreement estimated $58 million in-service cost, FCG asserted its actual project costs for the total for the LNG facility is $68 million, with an in-service date of March 2023; therefore, only the incremental $10 million is at issue in this proceeding. FCG argued that no party disputed that the LNG facility is needed to serve customers, and OPC agreed to the need for this facility in the 2018 Settlement Agreement. FCG averred that despite its efforts to secure additional capacity, it has been unable to do so at a reasonable cost, and therefore, the LNG facility remains a necessary option to provide capacity during peak periods for the Miami-Dade County area.

Although OPC acknowledged that some recovery of expenses associated with the LNG facility were allowed under the 2018 Settlement Agreement, OPC argued that it is unjust that customers have been paying for a facility that is not yet in-service. OPC expressed concerns that funds already received from customers could potentially result in customers overpaying for the LNG facility or otherwise could result in double recovery for the utility. Accordingly, OPC recommended that any funds that have been collected prematurely from ratepayers related to the LNG facility be accounted for in a regulatory liability and returned to ratepayers over five years.

Regarding OPC's implication of possible double recovery, FCG argued that its proposed base rate increase only includes the revenue requirements for the incremental $10 million for the LNG facility, and thus, is net of the $2.5 million in current rates associated with the LNG facility, and the previously approved increase of $3.8 million when the LNG facility enters service. Therefore, FCG asserted that there is no double recovery associated with the LNG facility.

2. Analysis

The LNG facility would provide 10,000 Dekatherms/day of pipeline capacity equivalent, and consists of three storage tanks holding 270,000 gallons of LNG and associated vaporization and delivery equipment. The LNG facility was originally proposed as part of FCG's 2017 base rate proceeding, and was included in several terms of the 2018 Settlement Agreement.[5] The 2018 Settlement Agreement determined that the LNG facility was needed to address the peak capacity concerns on FCG's system in the Miami-Dade County area, and should be allowed in rate base. As part of the 2018 Settlement Agreement, a portion of the revenue requirement associated with the then estimated $58 million in-service cost was included, with a term allowing a base rate increase to recover the full estimated cost upon either the end of 2019 or the in-service date of the facility, whichever was later.

Since the approval of the 2018 Settlement Agreement, the estimated in-service date has shifted to March 2023, with a total estimated in-service cost of $68 million. The primary cause of this shift is the loss of the originally proposed site as a viable location for the LNG facility, and the resulting in-service date delay. Due to being unable to acquire the necessary zoning and permitting approvals for the original site, FCG ultimately decided to sell the site and acquire a new site, which took additional time and delayed the in-service date. As part of this record, we reviewed the continued need for the LNG facility, the appropriate amount to include in rate base for the facility, in-service date concerns, and OPC's refund and cost disallowance proposals, as discussed below.

a. Need for the LNG Facility

While we previously approved the need for the LNG facility under the 2018 Settlement Agreement, and no party has disputed the continued need for the facility, we have noted in a prior proceeding that prudent utility managers continually reassess the need for a project or facility as circumstances change.[6]

OPC did not take issue with the need for the LNG facility. Rather, it offered that FCG failed to properly and prudently plan the project and thus, the incremental costs of the LNG facility should be borne by the shareholders, not the customers.

FCG provided testimony demonstrating that the LNG facility is fully permitted and was on schedule to begin LNG deliveries in January 2023 and meet its projected March 2023 in-service date and that the LNG is still needed. To further support the need of the LNG facility, FCG witness Howard testified that FCG needs additional interstate pipeline capacity to meet the needs of its Sales and Essential Use Transportation customers primarily in the Miami-Dade County area, and that there is currently a single source of FCG capacity in that area but that source has no additional incremental capacity available. FCG witness Howard argued that to

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[5] Order No. PSC-2018-0190-FOF-GU, issued April 20, 2018, in Docket No. 20170179-GU, *In re*: *Petition for rate increase and approval of depreciation study by Florida City Gas*.
[6] *See* Order No. PSC-12-0187-FOF-EI, issued April 9, 2012, in Docket No. 20110309-EI, *In re: Petition to determine need for modernization of Port Everglades Plant, by Florida Power & Light Company.*

date, FCG has been unable to acquire any additional interstate capacity at terms and pricing that are acceptable and reasonable to serve customers in the area. In addition, FCG explained that there are no other existing alternatives to strengthen reliability at the southern-most portion of FCG's system outside of the FGT pipeline.

In addition, FCG witness Howard offered the following testimony to support the continued need for the LNG facility:

- Reliably serving customers at this portion of its system is becoming increasingly constrained due to customer growth in that area as shown by supporting documentation demonstrating the consumption increase in this area since 2018.

- The LNG facility will help address specific capacity shortages on its system.

- It would be prudent to add resiliency to ensure FCG can continue to provide safe and reliable service to customers located at the southern-most portion of its system.

- The LNG facility appears to be the only cost-effective alternative available and is necessary to help reinforce the southern-most portion of FCG's system.

Accordingly, we find that the LNG facility is still needed for FCG to reliably serve its customers.

b. LNG Facility Cost

As part of the 2018 Settlement Agreement, we have already approved the inclusion of $58 million in rate base for the LNG facility. The $58 million is not disputed. What is disputed is any costs associated with the LNG facility that are in excess of the $58 million. FCG's first choice for the site required obtaining a special or unusual use zoning exemption due to its location outside of Miami Dade County's urban development boundary. Although FCG received support from County staff, FCG was ultimately denied the required exemption, forcing the Company to search for an alternative site.

Due to the need to relocate the site and the associated components, such as environmental studies, permitting, and the need to extend the pipeline connection, FCG updated its project cost estimate by an incremental $10 million to a total of $68 million. These increased project costs have already been offset by $2.2 million in benefits from the sale of the original site.

No party disputes the selection of the alternative site as an appropriate site to construct the LNG facility. Rather, OPC disputes that the costs of finding the alternate site should be borne by FCG shareholders, not customers.

Although OPC witness Schultz acknowledged the difficulties FCG experienced that contributed to the delay in constructing the LNG facility, he recommended that we disallow the additional cost of $10 million for the LNG facility because FCG failed to properly and prudently plan the project. Witness Schultz testified that it is not prudent to buy property zoned residential and plan industrial construction in the hopes that a zoning change will be allowed.

FCG witness Howard rebutted witness Schultz's testimony by arguing that the original site for the LNG facility was not zoned as residential, but as agricultural and agricultural accessory uses. He also testified that FCG did not acquire the original site in the hope that the zoning for the site would be changed, but FCG undertook due diligence with the County Planning Director regarding the consistency of the LNG facility within the established zoning requirements.

We find that FCG has acted prudently. The Community Council's decision to deny FCG's zoning exemption request for the original site, as well as the amount of time the process of locating and acquiring the necessary approvals for a new site took to reach completion, were beyond FCG's control. As such, we find that the additional cost of $10 million for the LNG facility was prudently incurred.

c. In-Service Date

FCG projects an in-service date of March 2023 for the LNG facility. In his testimony, OPC witness Schultz expressed concerns regarding whether the LNG facility will be in service when FCG projects since the in-service date for the facility has already been delayed by more than three years. Specifically, witness Schultz argued that it would not be appropriate for customers to again pay for plant not yet in-service. As such, witness Schultz recommended that any projected depreciation included in rates associated with the LNG facility be reflected as a regulatory liability and deferred until FCG's next rate case, or be reflected as a credit adjustment in one of the Commission's annual cost recovery clauses at a Weighted Average Cost of Capital (WACC) that recognizes the cost carried in rates.

FCG indicated that construction of the LNG facility began in June 2022. In addition, FCG witness Howard testified that construction of the LNG facility was essentially complete. Witness Howard also rebutted witness Schultz's testimony regarding this issue by outlining the activities completed with regard to the LNG facility from the time of the 2018 Settlement Agreement to this proceeding, as detailed above, in order to demonstrate that FCG has continued to act prudently.

Paragraph III(a) of the 2018 Settlement Agreement, of which OPC is a signatory, contemplates that the in-service date of the LNG facility could occur at some point after December 1, 2019.[7] In addition, as previously discussed, witness Schultz acknowledged the obstacles encountered by FCG that contributed to the delay of the LNG facility. As construction of the LNG facility is almost complete, we find no adjustments necessary to projected depreciation for the LNG facility.

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[7] Order No. PSC-2018-0190-FOF-GU, issued April 20, 2018, in Docket No. 20170179-GU, *In re*: *Petition for rate increase and approval of depreciation study by Florida City Gas.*

d. LNG Facility Costs in Current Base Rates

OPC witness Schultz testified that it was OPC's understanding that customers would not be paying for the LNG facility until it was in service. FCG witness Fuentes rebutted witness Schultz's testimony by asserting that OPC agreed to this ratemaking treatment as part of FCG's 2018 Settlement Agreement. Witness Fuentes disagreed with witness Schultz that funds that have been collected from ratepayers related to the LNG facility should be accounted for in a regulatory liability and returned to ratepayers over five years because this treatment is in direct violation of the 2018 Settlement Agreement.

OPC admitted in its brief that some recovery for the LNG facility was allowed under the 2018 Settlement Agreement. The 2018 Settlement Agreement allowed recovery of $29 million in rate base for the LNG facility before it came in-service, and approved an increase to $58 million in rate base upon entering service.[8] FCG's updated total project cost estimate is $68 million. As the $58 million project cost estimate was previously approved in the 2018 Settlement Agreement, FCG is only requesting approval of the incremental $10 million project cost increase in this proceeding; therefore, there is no possibility of double recovery. Since the ratemaking treatment for the LNG facility was agreed upon as part of the 2018 Settlement Agreement and there is no possibility of double recovery, we agree with FCG witness Fuentes that there is no need to set aside funds that have already been collected from ratepayers related to the LNG facility in a regulatory liability and amortized back to ratepayers over five years.

3. Conclusion

We find that the LNG facility is still needed for FCG to serve its customers reliably and the additional cost of $10 million for the LNG facility was prudently incurred. We find that no adjustments to projected depreciation for the LNG facility are necessary, and there is no need to set aside funds that have already been collected from ratepayers related to the LNG facility in a regulatory liability and amortized back to ratepayers. Therefore, we find the appropriate amount of plant in service for FCG's delayed LNG facility, once it is placed in service, is $68 million.

D. Plant in Service

1. Parties' Arguments

FCG stated that the appropriate amount of plant in service for the projected test year of 2023 is $664,736,539, including the acquisition adjustment. FCG has projections to invest more than $290 million to support customer growth and enhance both customer service and the safety and reliability of its system. FCG stated that it practices a rigorous and long-standing process for the development of capital expenditure budgets, financial forecasts, and MFRs, and noted that none of the Intervenors disproved of its forecasting methodologies. FCG argued it is able to secure the capital expenditures at the lowest reasonable cost using competitive bidding, contractor quality assurance, and cost tracking. FCG also argued that cost of construction has

[8] Id.

increased due to: increases in inflation and material costs; industry market demand for external contractors; supply chain issues; governmental, regulatory, and compliance requirements, including permitting and maintenance of traffic requirements; retirement, removal, and restoration costs; construction safety protocols; and enhanced construction management, inspection, and quality control.

OPC argued that FCG overstated its capital additions because capital expenditures were only \$36.6 million and \$40.9 million for 2019 and 2021, respectively, and the projections for 2022 and 2023 are \$89.4 million and \$50.6 million, respectively. OPC asserted that the actual 2020 capital expenditures might be an anomaly due to \$12 million in major improvements for a new customer and \$10 million in system investments, therefore making the increases for 2022 and 2023 more extreme. OPC noted that the 2022 budget-to-actual spending shows an overstatement averaging \$36,954,004. OPC acknowledged that unaccounted for SAFE costs in the actuals could cause the \$36,954,004 overstatement, but OPC deemed that FCG did not adequately provide information to determine if the overstatement was due to SAFE costs.

OPC contended that because FCG did not provide sufficient information to complete an analysis, and, according to FCG witness Howard, the Company is spending \$9 million below the projected plant for the capital expenditures for January to September 2022, an adjustment of \$9,637,988 should be made. This reduction is based on subtracting the actual three-year average of plant additions from the estimated 2022 plant additions. OPC also recommended a corresponding reduction of \$307,256 to depreciation expense and a \$460,884 reduction to accumulated depreciation to reflect a year and a half of depreciation.

2. <u>Analysis</u>

OPC witness Schultz testified that FCG's plant additions are overstated. Schultz calculated the three-year actual average of capital expenditures to be \$30,951,611, excluding the LNG facility, and determined the projected 2022 and 2023 capital expenditures, excluding the LNG Facility, to be \$20,014,315 and \$21,542,902, respectively, over the three-year actual. Witness Schultz continued that FCG having an approximate 67 percent increase in projected capital expenditures over the actual average is cause for concern. Witness Schultz also asserted concern that 2020 capital spending may be an anomaly because of high actual costs from \$12.2 million for major improvements for a new customer and \$10 million for a systems investment. OPC witness Schultz determined there to be an average overstatement of \$36,954,004 in a six-month period, between January and June 2022, between the Company's MFRs and its responses provided in discovery. Witness Schultz conceded that the discrepancy could be due to the SAFE plant not being included in the discovery response, but being included in the MFRs.

FCG argued that historical data is useful to evaluate the reasonableness of a forecast, but should not replace a forecast for a growing business in which the Company's plant additions for the 2023 test year are considered prudent. FCG witness Campbell responded that OPC witness Schultz should not have used historical averages because they are not representative of a prudent forecast for the projected test year, and that he used data that only provided retail base and did not include data for all clause investments. Witness Campbell recalculated the historical averages with the Company's corrected adjustments, and applying witness Schultz's methodology, argued that there would be a $2,134,806 increase to plant-in-service instead of the $9,637,988 decrease that witness Schultz recommended.

3. Conclusion

We find no adjustments to the Company's projected plant in service are necessary, and the appropriate level of plant in service for the projected test year is $643,079,704.

E. Non-Utility Activities

At hearing, we approved a stipulation whereby all parties agreed that FCG does not have any non-utility investments, and no adjustments to remove non-utility activities from Plant in Service, Accumulated Depreciation, and Working Capital are necessary.

F. Acquisition Adjustment

1. Parties' Arguments

The acquisition adjustment at issue relates to the acquisition of FCG by AGL Resources, Inc., (AGLR) in 2004, which we approved in 2007 via final Order.[9] Since the Commission approved this initial acquisition adjustment, the utility has changed ownership twice. In 2016, AGLR was acquired by Southern Gas Company (Southern). The Company was later acquired by NextEra Energy, Inc., (NEE) the parent company of Florida Power & Light Company (FPL), in 2018. FCG continues to amortize the AGLR acquisition adjustment approved in 2007. The amount of the AGLR acquisition adjustment is $21.7 million, and the related accumulated amortization is $13.5 million for a net balance of $8.2 million included in rate base. Amortization expense of $0.7 million is reflected in net operating income in the 2023 Test Year.

In its brief, OPC relied on prior Commission orders in support of its argument to deny the acquisition adjustment. Conversely, FCG relied on separate Commission orders in support of Commission approval of the acquisition adjustment.

FCG argued that the permanence and continuation of the acquisition adjustment and related amortization were consistent with prior Commission orders.[10] FCG further argued that because it carried over the amounts reflected in the balance sheet at the time of the acquisition from Southern in July 2018, as opposed to recording an acquisition adjustment from the transaction, it should be allowed to continue to carry the acquisition adjustment. FCG also argued that OPC's reliance on prior water and wastewater orders of this Commission is misplaced.

[9] Order No. PSC-07-0913-PAA-GU, issued November 13, 2007, in Docket No. 20060657-GU, *In re: Petition for approval of acquisition adjustment and recognition of regulatory asset to reflect purchase of Florida City Gas by AGL Resources. Inc.*
[10] Order No.PSC-2018-0190-FOF-GU, issued April 20, 2018, in Docket No. 20170179-GU, *In re: Petition for rate increase by Florida City.*

2. Analysis

The Commission approved the adjustment from the 2004 acquisition and required the review of the savings that supported the acquisition adjustment in the next rate proceeding following the acquisition in 2007. The Commission authorized the 30-year amortization period for the acquisition adjustment after analyzing the five factors it has historically reviewed when considering acquisition adjustments for natural gas utilities.[11] These factors address the quality of service, operating costs, ability to attract capital for improvements, overall cost of capital, and the professionalism and expertise of the staff.[12]

While OPC cited two orders showing that the Commission has an established policy that acquisition adjustments resulting from previous transactions do not survive subsequent purchases of a utility's assets, FCG presented countervailing testimony regarding Commission orders where the adjustment was continued.[13] FCG witness Fuentes testified that, rather than recording a new acquisition adjustment from its acquisition by Southern, it carried over the amounts already reflected in the balance sheet at the time of the acquisition.

3. Conclusion

We are persuaded by the testimony of FCG's witnesses and find that the amortization of the acquisition adjustment shall continue until the next general rate case, at which time FCG will have to support its further continuance under the five factors this Commission has historically reviewed when considering acquisition adjustments for natural gas utilities.

G. Construction Work in Progress (CWIP)

At hearing, we approved a stipulation whereby all parties agreed that the appropriate amount of Construction Work in Progress (CWIP) is $28,192,440 for the 2023 projected test year.

H. Gas Plant Accumulated Depreciation and Amortization

1. Parties' Arguments

FCG stated that the appropriate amount of Accumulated Depreciation for the projected test year, including accumulated amortization associated with the acquisition adjustment, is $221,380,711. FCG argued that OPC's recommended $13.2 million adjustment to Accumulated Depreciation is unsupported, inappropriate, and should be rejected.

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[11] *Id.*
[12] *Id.*
[13] Order No. PSC-03-0038-FOF-GU, issued January 6, 2003, in Docket No. 020384, *In re: Petition for rate increase by Peoples Gas Systems;* and Order No. 23858, issued December 11, 1990, in Docket No. 891353, *In re: Application of PEOPLES GAS SYSTEMS, INC. for a rate increase.*

OPC maintained that the appropriate level of Accumulated Depreciation and Amortization for the projected test year should be at least $208,172,408, as recommended by OPC witness Schultz.

2. Analysis and Conclusion

This issue is determined by our findings on other issues, and based on our findings regarding the Company's Depreciation Study and the Company's acquisition adjustment, the appropriate level of Gas Plant Accumulated Depreciation and Amortization is $221,380,711.

I. Under-Recoveries and Over-Recoveries in Working Capital Allowance

At hearing, we approved a stipulation whereby all parties agreed that under recoveries and over recoveries related to the Purchased Gas Adjustment, Energy Conservation Cost Recovery, and Area Expansion Plan have been appropriately reflected in the Working Capital Allowance.

J. Unamortized Rate Case Expense.

1. Parties' Arguments

FCG Witness Fuentes asserted that the inclusion of the unamortized balance of Rate Case Expense of $1,645,732 for the 2023 projected test year in Working Capital is appropriate to avoid an implicit disallowance of reasonable and necessary costs. FCG also argued that its four-year rate plan would reduce the amount of Rate Case Expense that FCG would otherwise incur for multiple rate cases. FCG submitted that it is appropriate to include the unamortized Rate Case Expense in Working Capital.

FCG requested that the 13-month average of unamortized Rate Case Expense be allowed in Working Capital. FCG witness Fuentes testified that the Company requested the unamortized balance be included in rate base in order to "avoid an implicit disallowance of reasonable and necessary costs." She maintained that full recovery of necessary Rate Case Expense is not limited to only recovering the expense and should also include affording FCG the opportunity to earn a return on the unamortized balance of those expenses in Working Capital.

OPC asserted that unamortized Rate Case Expense should not be included in Working Capital for a gas company pursuant to Commission policy. OPC witness Schultz proposed a reduction to Working Capital for the deferred Rate Case Expense based on his recommendation to reduce the total Rate Case Expense.

2. Analysis

There are electric and gas rate cases that reflect the Commission's allowance of one-half of Rate Case Expense in Working Capital.[14] However, there are no Commission Orders reflecting the full allowance. In Progress Energy Florida, Inc.'s (PEF) 2009 Rate Case, the Commission denied PEF's request to include unamortized Rate Case Expense in Working Capital.[15] The Order in PEF's 2009 Rate Case stated that customers and shareholders should share the cost of a rate case based on the belief that customers should not be required to pay a return on funds used to increase their rates.[16] The Order also cited other electric and gas rate cases where the Commission denied unamortized Rate Case Expense in Working Capital.[17]

FCG's justification for full allowance was essentially its assertion that disallowance prevents the Company from fully recovering all necessary and reasonable costs. We are not persuaded that this assertion is enough to contradict Commission policy. We find that FCG has failed to meet the burden to support the inclusion of any unamortized Rate Case Expense in Working Capital, and therefore Working Capital should be decreased by $1,742,227.

3. Conclusion

Inclusion of FCG's requested full unamortized amount of Rate Case Expense in Working Capital would be a departure from Commission practice. As such, Working Capital shall be decreased by $1,742,227.

K. Deferred Pension

At the hearing, we approved a stipulation whereby all parties agreed that the appropriate amount of deferred pension debit in working capital for FCG to include in rate base is $4,604,263 for the 2023 projected test year.

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[14] *See* Order No. PSC-94-0170-FOF-EI, issued on February 10, 1994, in Docket No. 19930400-EI, *In re: Application for a Rate Increase for Marianna electric operations by Florida Public Utilities Company*; Order No. PSC-08-0327-FOF-EI, issued on May 19, 2008, in Docket Nos. 20070300-EI and 20070304-EI, *In re: Petition for rate increase by Florida Public Utilities Company*; Order No. PSC-04-0369-AS-EI, issued on July 2, 2004, in Docket No. 20030438-EI, *In re: Petition for rate increase by Florida Public Utilities Company*; Order No. PSC-04-1110-PAA-GU, issued on November 8, 2004, in Docket No. 20040216-GU, *In re: Application for rate increase by Florida Public Utilities Company*; and Order No. PSC-95-0518-FOF-GU, issued on April 26, 1995, in Docket No. 940620-GU, *In Re: Application for a rate increase by FLORIDA PUBLIC UTILITIES COMPANY*.

[15] Order No. PSC-10-0131-FOF-EI, issued on March 5, 2010, in Docket Nos. 20090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc.*; 20090144-EI, *In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.*; and 20090145-EI, *In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.*

[16] Order No. PSC-10-0131-FOF-EI.

[17] *See* Order No. 23573, issued October 3, 1990, in Docket No. 891345-EI, *In re: Application of Gulf Power Company for a rate increase*; Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, *In re: Petition for rate increase by Tampa Electric Company*; Order No. PSC-09-0375-PAA-GU, issued May 27, 2009, in Docket No. 080366-GU, *In re: Petition for rate increase by Florida Public Utilities Company.*

L. Unbilled Revenues

At the hearing, we approved a stipulation whereby all parties agreed that unbilled revenues shall be included in working capital. FCG incurs costs to deliver gas to customers, all of which have been accrued or paid. Delivery of that gas gives rise to both customer accounts receivables and a receivable for unbilled revenues. FCG must finance the costs of delivering gas, whether or not the gas sales have yet been billed. For this reason, the Commission has a long-standing practice of including unbilled revenues in working capital.

M. Working Capital

1. Parties' Arguments

FCG claimed the appropriate amount of working capital for the 2023 projected test year is $17,357,425. FCG stated that OPC witness Schultz ignored the forecasted Cash Working Capital (CWC), and instead, limited his evaluation to the historical CWC balances. FCG explained the primary reasons for this CWC increase were Cash, Accounts Receivable, Stored Fuel, and Miscellaneous Deferred Debits. FCG has a target minimum for cash of $5 million in projected periods and requests funds as needed for working capital from FPL on an ongoing basis, which establishes the minimum cash balance target. Accounts receivables are increasing in line with increased revenue. Stored fuel increase is due to fuel prices rising and the opening of the LNG facility. Miscellaneous Deferred Debits increased due to a rise in the Company's pension asset. FCG further stated that the CWC should utilize projections as opposed to historical averages.

OPC stated that based on historical balances, the Company's request for CWC is improperly inflated with increases significantly larger than historical averages. OPC recommended an $800,000 decrease to Accounts Payable. OPC recommended a disallowance of $7,850,000. OPC claimed that these reductions result in a debit balance greater than the three-year average for each expense.

2. Analysis

FCG requested $17,357,425 for the total amount of working capital if the RSAM was approved. The parties' disagreements over working capital are broken down into Cash, Accounts receivable, Stored Fuel, Miscellaneous Deferred Debits, and Accounts Payable.

OPC witness Schultz testified that several CWC components were significantly higher than the historical amounts. CWC and working capital allowance are the same. FCG requested $5 million for Cash while the average in prior years was only $2,312,949. The request for Accounts Receivable reflects an increase by $6,225,528 over the three-year average of $9,278,408. The stored fuel is double the three-year average and Miscellaneous Deferred debits is three times the three-year average.

In his adjustments, witness Schultz recommended reductions to Cash, Accounts Receivable, Gas Storage, and Miscellaneous deferred Debits. The total amount of adjustment to assets in working capital is an $8,650,000 decrease. Witness Schultz also recommended an $800,000 decrease to Accounts Payable. The total of witness Schultz's adjustments is a $7,850,000 decrease to working capital.

FCG witness Howard claimed that witness Schultz ignored the forecasted Cash Working Capital and used historical CWC as the basis for his adjustments. For Cash, FCG witness Howard testified that FCG requests funds from FPL as needed and that this set the minimum cash balance target from FCG. Witness Howard testified that FCG projects accounts receivable using 2021 historical average days' sales outstanding and then applied that ratio to projected revenues. Witness Howard states that the increase in stored fuel is due to the increase in natural gas prices and the anticipated opening of the LNG facility in March 2023. FCG contended the adjustments proposed by OPC reflect historical amounts while ignoring projected amounts.

3. Conclusion

We agree with the Company's rationale. The use of the historic trends, while a good resource for evaluation, are lacking as a basis for adjustment in the projected test year. Historical data does not account for the changes made in the projected test year nor does it account for FCG's change in ownership since its last rate case. Based on that premise and using indexed amounts, we looked at working capital as a whole and found the amount to be reasonable. Taking into account our findings regarding accumulated depreciation, under and over recoveries, unamortized rate case expense, deferred pension, unbilled revenues, and insurance expense, the appropriate level of working capital for the projected test year is $15,709,607.

N. Rate Base

1. Parties' Arguments

FCG stated that the testimony of its witnesses, information in its MFRs, and discovery responses fully support the amount of rate base requested. Therefore, FCG contended the appropriate amount of rate base for the 2023 projected test year is $487,326,330.

OPC stated that the appropriate level of rate base for the projected test year should reflect all OPC adjustments. The appropriate amount of rate base should be no more than $455,035,463.

2. Analysis and Conclusion

The appropriate level of rate base depends on the outcome of other issues. Based on our findings regarding the acquisition adjustment, the unamortized rate case expense, and working capital, the appropriate level of rate base for the projected test year is $487,257,875.

VI. Cost of Capital

A. Accumulated Deferred Taxes

1. Parties' Arguments

FCG asserted it has incorporated an adjustment to decrease the amount of accumulated deferred income tax (ADITs) included in the calculation of FCG's weighted average cost of capital as required under Treasury Regulations §1.167(1)-1(h)(6). The calculation of the proration requirement for ADITs for the 2023 projected test year results in a decrease of $46,471. FCG argued that with this adjustment, the appropriate amount of ADITs with the RSAM included in capital structure for the projected test year is $53,898,912. FCG asserted that OPC recommended a $3.6 million decrease to ADITs based on OPC witness Schultz's recommended rate base adjustments. FCG argued that OPC's rate base adjustments should be rejected and therefore OPC's corresponding adjustment to ADIT for the projected test year should also be rejected.

While OPC did not address accumulated deferred taxes in its post-hearing brief, OPC recommended a cumulative reduction to rate base of $32,387,362, which corresponds to a decrease of $3,571,766 to ADITs when reconciled to the capital structure pro rata over all sources of capital. OPC argued the appropriate amount of ADITs to include in the capital structure is at least $50,182,538.

2. Analysis

The appropriate amount of accumulated deferred taxes in the projected test year capital structure differs slightly between FCG's and OPC's recommendations. To derive its deferred tax balance, FCG made a pro rata adjustment of $1,349,743 to its per books balance of $55,150,517, reducing it to reconcile it with the total projected rate base balance. FCG made an additional proration adjustment to remove $46,471 to comply with U.S. Treasury Regulations §1.167(1)-1(h)(6) which is necessary when calculating rates using a projected test year. None of the parties objected to FCG's proration adjustment.

In addition, FCG made a correction to its revenue requirement which affected the rate base amount, and thus, the capital structure balance. None of the parties made a specific objection to FCG's calculation of the amount of ADITs included in its MFR Schedule G-3 or FCG's recalculated ADITs amount in Exhibit LF-12, included with FCG witness Fuentes' rebuttal testimony. However, OPC recommended a deferred tax balance of $50,182,533, which is based on OPC witness Garrett's proposed capital structure that includes a ratio of 11.03 percent for deferred taxes. The difference in OPC's recommended amount arises from OPC's recommendation to make adjustments to reduce FCG's rate base and reconcile the lower rate base amount pro rata over all capital sources, which lowers the deferred tax balance proportionately. In the previous section, we approved a total rate base amount of $487,257,875. When this amount is reconciled pro rata over all capital sources to FCG's capital structure, the corresponding amount of accumulated deferred income taxes based on a ratio of 11.02 percent is $53,717,249.

3. Conclusion

For the aforementioned reasons, we find the appropriate amount of accumulated deferred income taxes to include in the projected test year capital structure ending December 31, 2023, is $53,717,249.

B. Short-Term Debt

1. Parties' Arguments

FCG argued the appropriate amount and cost rate for short-term debt for the projected test year is $20,203,793 and 1.78 percent, respectively. FCG asserted it utilized FPL's short-term debt cost because, pursuant to Commission-approved financing orders,[18] FCG obtains 100 percent of its debt and equity financing from FPL and the interest rate on any short-term borrowings by FCG from FPL is a pass-through of FPL's weighted cost for borrowing these funds. FCG argued FPL relies on the forward Intercontinental London Interbank Exchange Offered Rate (LIBOR) curve for its short-term debt cost projections. FCG argued that OPC's recommended adjustments to increase the amount of short-term debt included in the investor sources of capital by $20,269 should be rejected. FCG also argued that OPC's recommended adjustment to decrease the total rate base balance should be rejected, and therefore, OPC's corresponding adjustment to decrease the amount of short-term debt in the capital structure for the projected test year should also be rejected.

OPC did not address short-term debt in its post-hearing brief, but OPC witness Garrett testified that the appropriate ratio of short-term debt in the projected test year capital structure is 4.13 percent. This ratio equates to a balance of $18,821,767 for short-term debt in OPC witness Shultz's cost of capital schedule when reconciled to OPC's recommended rate base balance of $455,035,463. OPC did not object to FCG's cost rate of 1.78 percent for short-term debt.

2. Analysis

Both FCG and OPC agree the appropriate cost rate for short-term debt is 1.78 percent. We reviewed FCG's estimate for the short-term debt cost rate based on LIBOR as provided in FCG's discovery responses and find it to be reasonable. FPL, as FCG's parent, provides all the investor-provided capital to FCG at the capital structure ratios of FPL. FCG applied the capital structure of FPL, which includes a ratio of 4.69 percent of short-term debt, to its projected test year capital structure and reconciled the amounts to the rate base balance for the projected test year via a pro rata adjustment over all capital sources. After reconciliation with all capital structure components, the ratio of short-term debt in the projected test year capital structure is 4.13 percent. This ratio equates to a short-term debt balance of $20,203,793.

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[18] Order No. PSC-2022-0354-FOF-EI, Issued October 19, 2022, in Docket No. 20220133-EI, *In re: Application for authority to issue and sell securities during calendar year 2023 and 2024, pursuant to Section 366.04, F.S., and Chapter 25-8, F.A.C., by Florida Power & Light Company and Florida City Gas.*

FCG recalculated its revenue requirement which included a reduction to its requested rate base for the projected test year. As a result, the rate base was reduced by $96,495, which resulted in a corresponding reduction to short-term debt of $3,987. FCG's final amount of short-term debt included in its projected test year capital structure was $20,137,159. OPC witness Garrett suggested a ratio of 4.13 percent for short-term debt in the projected test year capital structure. When OPC's recommended capital structure is reconciled to OPC's recommended lower rate base balance, the corresponding amount of short-term debt is $18,821,767. Previously, we approved a total rate base amount of $487,257,875. When this amount is reconciled pro rata over all capital sources to our approved capital structure, the corresponding amount of short-term debt based on a ratio of 4.13 percent is $20,135,698.

3. Conclusion

In conclusion, both FCG and OPC agree on the cost rate of 1.78 percent for short-term debt in the projected test year capital structure and we find it to be a reasonable rate. Based on the aforementioned, we find the appropriate amount and cost rate for short-term debt to include in the projected test year capital structure ending December 31, 2023, is $20,135,698, at a cost rate of 1.78 percent.

C. Long-Term Debt

1. Parties' Arguments

FCG argued the appropriate amount and cost rate for long-term debt for the projected test year is $154,025,674 (adjusted) and 4.28 percent, respectively. FCG argued it does not issue its own debt or equity and, pursuant to Commission-approved financing orders,[19] FCG obtains 100 percent of its debt and equity financing from FPL, and the interest rate on any short-term or long-term borrowings by FCG from FPL is a pass-through of FPL's weighted cost for borrowing these funds. FCG witness Campbell contended that this is a significant benefit to FCG's customers because FPL's weighted average borrowing costs are significantly lower than FCG could otherwise obtain on its own. FCG argued OPC's recommended net increase of approximately $54.6 million in long-term debt to reflect OPC's proposed capital structure should be rejected, and therefore, its corresponding adjustment to long-term debt should also be rejected.

OPC did not proffer a specific argument in its post-hearing brief, but recommended an increase of $54.6 million in long-term debt to reflect OPC's proposed capital structure. OPC also recommended an additional decrease of $13.8 million in long-term debt based on OPC witness Schultz's recommended rate base adjustments. OPC witness Garrett testified his analysis strongly indicates that FCG's proposed long-term debt ratio of 40.4 percent is too low to be considered fair for ratemaking. Witness Garrett opined an insufficiently low debt ratio causes the weighted average cost of capital to be unreasonably high. Based on his findings, witness Garrett

[19] Order No. PSC-2022-0354-FOF-EI, Issued October 19, 2022, in Docket No. 20220133-EI, *In re: Application for authority to issue and sell securities during calendar year 2023 and 2024, pursuant to Section 366.04, F.S., and Chapter 25-8, F.A.C., by Florida Power & Light Company and Florida City Gas.*

recommended the Commission impute a capital structure for ratemaking purposes consisting of long-term debt of 51.3 percent.

2. Analysis

Both FCG and OPC agree the appropriate cost rate for long-term debt is 4.28 percent. The amount of long-term debt in the projected test year capital structure differs between FCG's and OPC's recommendations. FPL provides all the investor-provided capital to FCG at the capital structure ratios of FPL. FCG applied the capital structure of FPL, which includes 40.4 percent of long-term debt, to its projected test year capital structure and reconciled the amounts to the rate base balance for the projected test year via a pro rata adjustment over all sources. After reconciliation with all capital structure components, the ratio of long-term debt in the projected test year capital structure is 31.50 percent. This ratio equates to a long-term debt balance of $154,056,074. FCG subsequently recalculated its revenue requirement which included a reduction to its requested rate base for the projected test year. As a result, the rate base was reduced by $96,495, which resulted in a corresponding reduction to long-term debt of $30,400. FCG's adjusted amount of long-term debt included in its projected test year capital structure was $154,025,674.

There was competing testimony about FCG's requested long term debt ratio of 31.50 percent. FCG Witness Garrett testified that an insufficiently low debt ratio causes the weighted average cost of capital to be unreasonably high and recommended the Commission impute a capital structure for ratemaking purposes consisting of 51.3 percent total debt based on investor sources of capital. OPC witness Shultz used witness Garrett's recommended long-term debt ratio of 42.7 percent to develop his recommended projected test year capital structure. Reconciling OPC's recommended capital structure pro rata over all sources to OPC's recommended rate base balance, the corresponding amount of long-term debt in the projected test year capital structure would be $194,277,560.

OPC is proposing an adjustment to increase the amount of long-term debt in the projected test year capital structure as a result of lowering the equity ratio. In rebuttal, FCG witness Nelson contended that increasing the Company's financial leverage by reference to publicly traded holding companies and other industry capital structures would increase FCG's financial risk and, as a result, its cost of capital to the detriment of customers.

FCG witness Campbell explained the Company utilized FPL's projected long-term debt rate of 4.28 percent because all long-term financings are provided by FPL. FCG stated FPL relies on the Blue Chip Financial Forecast to project its long-term debt costs, which represents the consensus estimates of more than 40 economists/contributors. FCG's cost projections for FCG's long-term borrowings from FPL are shown in MFR G-3, Page 3. FCG's blended long-term debt cost rate for the projected test year is shown in MFR Schedule G-3, Page 2. We reviewed the aforementioned MFR Schedules and believe the projected long-term debt cost rate of 4.28 percent is reasonable. Previously, we approved a total rate base amount of $477,497,041. When this amount is reconciled pro rata over all capital sources to our approved capital structure, the corresponding amount of long-term debt based on a ratio of 31.50 percent is $153,506,544.

3. Conclusion

Both FCG and OPC agree on the cost rate of 4.28 percent for long-term debt in the projected test year capital structure, and we find it to be a reasonable rate. Based on the aforementioned, the appropriate amount of long-term debt to include in the projected test year capital structure ending December 31, 2023, is $153,506,544 at a cost rate of 4.28 percent.

D. Customer Deposits

1. Parties' Arguments

FCG argued the appropriate amount for customer deposits for the 2023 Test Year is $3,799,283 (adjusted) at a 2.64 percent cost rate. FCG also argued against OPC witness Schultz's recommended rate base adjustments, and therefore, OPC's corresponding adjustment to decrease customer deposits by $251,671 for the projected test year should be rejected.

OPC did not address customer deposits in its brief. OPC witness Garrett proposed a ratio of 0.78 percent to include in the projected test year capital structure at a cost rate of 2.64 percent. OPC witness Shultz used witness Garrett's proposed capital structure to develop OPC's recommended amounts of the components in the projected test year capital structure. OPC recommended a customer deposit balance of $3,535,924 at a cost rate of 2.64 percent.

2. Analysis

Both FCG and OPC agree the appropriate cost rate for customer deposits is 2.64 percent. Both FCG and OPC agree on the ratio of 0.78 percent for customer deposits to include in the projected test year capital structure. FCG did not provide testimony specific to the amount of customer deposits to include in the test year capital structure. We have reviewed the customer deposit balance and effective cost rate as calculated by FCG and find them to be reasonable. FCG recalculated its base revenue requirement, which resulted in a corresponding adjustment to the original customer deposit balance leading to an adjusted balance for customer deposits of $3,799,283.

3. Conclusion

Based on the aforementioned, we find the appropriate amount and cost rate for customer deposits to include in the projected test year capital structure is $3,786,477 at a cost rate of 2.64 percent.

E. Equity Ratio

1. Parties' Arguments

FCG argued that its requested capital structure consisting of 59.6 percent common equity, which is the same equity ratio as FPL, should be approved because it receives all of its debt and equity financing directly from FPL. FCG opined that its proposal to use the capital structure of its parent is fully consistent with FCG's proposal in FCG's 2018 rate case, that the Commission has previously approved the use of a parent company's capital structure where the regulated utility operates as a division and does not issue its own debt, that its proposed equity ratio of 59.6 percent is within the range of the equity ratios of the gas utilities included in the proxy group, and that it is consistent with industry practice. FCG further argued that the Company's requested equity ratio reflects its specific financing requirements and risk profile, and enables it to maintain its financial strength, which translates into favorable access to capital for the benefit of customers.

To assess whether FCG's requested financial capital structure is consistent with industry practice, FCG witness Nelson calculated the average capital structure (including short-term debt) for each of the proxy group operating companies from 2018 to 2020. The results showed the mean and median three-year average equity ratio of the proxy group is 54.78 percent and 55.85 percent, respectively, within a range of 43.54 percent to 61.78 percent. Therefore, FCG concluded its requested equity ratio of 59.60 percent is within the proxy group range and consistent with industry practice.

OPC argued that witness Garrett's recommended debt ratio would result in an equity ratio of 46.9 percent, and therefore a debt-to-equity ratio of 1.13, which is consistent with the proxy group average. OPC asserted regulated utilities under a rate base rate of return model, where there is no competition, do not have an incentive to minimize their weighted average cost of capital (WACC) because a higher WACC results in higher rates, all else held constant. OPC argued that, because there is no incentive for a regulated utility to minimize its WACC, a Commission standing in the place of competition must ensure that the regulated utility is operating at the lowest reasonable WACC.

OPC witness Garrett used the same gas utility proxy group as that of FCG witness Nelson for his cost of capital analysis, and testified the average debt ratio of the proxy group of gas utility companies is 53.1 percent, which correlates to an equity ratio of 46.9 percent. Witness Garrett assessed the reasonableness of his recommendation by comparing other competitive firms with debt ratios above 56 percent from around the country and concluded that the average debt ratio was 64 percent (36 percent equity ratio). From his analyses, witness Garrett opined that FCG's proposed long-term debt ratio of 40.4 percent is too low to be considered fair for ratemaking and causes the WACC to be unreasonably high. Based on witness Garrett's testimony, OPC recommended an equity ratio of 46.9 percent from investor-supplied capital which is consistent with the gas utility proxy group average.

OPC witness Garrett disagreed with FCG's assertion that FCG should use the equity ratio of its parent FPL because FPL is the source of FCG's financing. OPC argued that regulators generally establish capital structures for utilities based on the operational and market risk factors that apply to the individual utility. Witness Garrett asserted that in the FPL 2021 rate case, FPL witness Barrett testified that FPL's regulatory capital structure included a 59.6 percent equity ratio and has maintained an equity ratio between 59 and 60 percent for over two decades. OPC argued that unlike FPL, FCG had maintained an equity ratio of just over 43 percent for the past twenty years, and it has been 48 percent since only mid-2018.

FEA argued FCG's requested common equity ratio of 59.6 percent is not appropriate and should be rejected because it exceeds the average authorized equity ratio of 51.4 percent for regulated gas utilities around the country and significantly exceeds the average common equity ratio for the gas utility proxy group of 38.6 percent. FEA argued that witness Walters relied on the same gas utility proxy group developed by FCG witness Nelson, but opined that FCG's assumed equity ratio of 59.6 percent is nearly eight percentage points higher than that of the gas utility proxy group's comparable equity ratio. Therefore, FEA argued, the Company's requested common equity ratio should be rejected and the Commission should approve a common equity ratio of no higher than 50.0 percent. FIPUG joined the arguments of FEA.

Witness Walters disagreed with witness Nelson's assessment that an equity ratio of 59.6 percent is reasonable because it is consistent with the source of the investor-supplied capital and it lies within the range of the equity ratios of the gas utility proxy group.

2. Analysis

FCG's current equity ratio is 48 percent, which is based on the consolidated capital structure of its former parent company Southern Company Gas in its 2018 rate case settlement. The revenue requirement associated with increasing the equity ratio from 48 percent to 59.6 percent is approximately $4.1 million.

Based on record evidence and past Commission practice of using a capital structure that approximates FCG's actual sources of capital, FCG's projected equity ratio of 59.6 percent for the test year ending December 31, 2023, is reasonable and appropriate. FCG presented testimony that the Company's requested equity ratio reflects its specific financing requirements and risk profile, and enables it to maintain its financial strength, which translates into favorable access to capital for the benefit of customers. FCG offered testimony that its requested financial capital structure is consistent with industry practice. For example, FCG witness Nelson testified the average capital structure (including short-term debt) for each of the proxy group operating companies from 2018 to 2020. The results showed the mean and median three-year average equity ratio of the proxy group is 54.78 percent and 55.85 percent, respectively, within a range of 43.54 percent to 61.78 percent. Therefore, FCG concluded its requested equity ratio of 59.60 percent is within the proxy group range and consistent with industry practice.

FCG also offered testimony that its requested equity ratio is appropriate because it is based on its actual financing from its parent, FPL, and is consistent with regulatory precedent and guidance regarding capital structure determinations for companies that do not issue their own debt or have their own credit ratings. While OPC witness Garrett's testified that using FPL as a gas utility proxy group was flawed, FCG witness Nelson testified that OPC witness Garrett incorrectly used the capital structures of the publicly traded holding companies, not the regulated operating companies that are subsidiaries of the holding companies. FCG argued the proper point of comparison is the mix of investor-supplied capital in place at the regulated utility operating companies, not at the publicly traded holding companies. Witness Nelson testified that the Intervenor witnesses' recommendations would increase FCG's financial risk and, in turn, its cost of capital to the detriment of customers. Furthermore, as FCG witness Nelson asserted, adverse weather events can happen in Florida, and maintaining a strong balance sheet that enables efficient access to capital when needed regardless of market environments is important.

3. Conclusion

Based on record evidence and past Commission practice of using a capital structure that approximates the utility's actual sources of capital, FCG's projected equity ratio of 59.6 percent for the test year ending December 31, 2023, is reasonable and appropriate. Accordingly, we find the appropriate equity ratio is 59.6 percent as a percentage of investor-supplied capital.

F. Return on Equity (ROE)

1. Parties' Arguments

FCG argued for a 10.75 percent return on common equity (ROE). FCG argued that a fair rate of return should be comparable to returns investors expect to earn on other investments of similar risk, sufficient to assure confidence in the company's financial integrity, and adequate to maintain and support the company's credit and to attract capital. FCG argued that this ROE would appropriately account for FCG's unique risk profile and the Company's commitment to a strong financial position, while addressing the risk of the Company's proposed multi-year stay-out. FCG argued that its requested ROE was critical to maintaining its financial strength and flexibility as well as attracting the capital necessary to serve its customers on reasonable terms.

OPC argued that the appropriate ROE should be 9.25 percent. OPC argued that since utility stocks are low risk, the return required by equity investors should be relatively low. OPC opined that if the Commission sets the awarded ROE much higher than the true cost of capital, it would run contrary to applicable U.S. Supreme Court precedent and result in an inappropriate transfer of wealth from customers to shareholders. OPC argued that an ROE of 9.25 percent would result in fair, just, and reasonable rates, and would benefit both FCG's consumers as well as FCG's shareholders.

FEA argued that the appropriate ROE is in the range of 9.00 percent to 9.80 percent, with a midpoint of 9.40 percent. FEA asserted that the purpose of the rate of return testimony provided is to estimate the expected return that investors require on an investment in FCG. FEA argued that a utility should be allowed an ROE sufficient to maintain its financial integrity and to attract capital on reasonable terms, and the return should be commensurate with returns investors could earn in other companies of comparable risk. FEA further argued that market valuations of utility stocks are strong, which is an indication that utilities are able to access equity capital at lower costs and under reasonable terms. FIPUG joined the position and argument of FEA.

2. Analysis

The ROE is the allowed cost of common equity. More simply put, ROE is the interest the customers pay to the investors for their equity investments in the utility. The ROE is included in a utility's regulatory capital structure used to determine the overall rate of return which, in turn, is used to establish a revenue requirement. Under section 366.041(1), F.S., no public utility shall be denied a reasonable rate of return.

The *Hope* and *Bluefield* U.S. Supreme Court cases established that a fair ROE must be (1) commensurate with returns available on investments having comparable risks, (2) sufficient to assure financial soundness and integrity and support reasonable credit quality, and (3) adequate to allow a company to raise capital on reasonable terms.[20] Neither case law nor statute mandate that the awarded ROE be tied to the result of a particular financial model. Rather, we must establish a reasonable ROE that is consistent with *Hope* and *Bluefield* and supported by competent, substantial evidence in the record. As recognized in this case by OPC witness Schultz, this Commission has a long history of establishing an ROE mid-point and a range of 100 basis points on either side to create a range of reasonableness and ensure rate stability.

FCG's common equity is not publicly traded, and as such a market-based cost rate for the Company cannot be directly observed. Consequently, FCG witness Nelson, OPC witness Garrett and FEA witness Walters (collectively, "Intervenor Witnesses") all applied cost of equity financial models to a proxy group of publicly traded gas distribution companies (proxy group) with similar risk to FCG to derive estimates of the required ROE. OPC witness Garrett and FEA witness Walters used the same proxy group as that of FCG witness Nelson. All three witnesses used the Discounted Cash Flow (DCF) model and the Capital Asset Pricing Model (CAPM) to estimate the cost of equity.

In addition, FCG witnesses Nelson and FEA witness Walters employed a risk premium analysis to estimate the cost of equity. Witness Garrett also applied the Hamada Formula to his CAPM. In general, FCG witness Nelson used inputs and assumptions for things such as projected market returns that produced a higher ROE estimate, while the Intervenor Witnesses used inputs and assumptions that produced a lower ROE estimate. As a result of the respective assumptions used in the cost of equity models, our staff's recommended ROE is greater than OPC's and FEA's recommended ROE of 9.25 percent and 9.4 percent, respectively, and lower than FCG's requested ROE of 10.75 percent. The range of results of all of the witnesses' cost of equity models is 7.10 percent to 13.37 percent. The witnesses' cost of equity model results are summarized in Table 2.

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

Table 2

ROE Model	FCG witness Nelson	OPC witness Garrett	FEA witness Walters
DCF with analyst growth estimates	8.4% - 10.87%	8.00%	9.31%
DCF with sustainable growth estimates	8.05% - 10.69%	7.1%	9.02%
DCF Multi-stage			7.99%
CAPM	10.12% - 10.94%	7.90%	8.08% - 10.97%
CAPM with Hamada Formula		9.0%	
Empirical CAPM	10.67% - 13.15%		
Risk Premium	9.73% and 9.80%		9.27% - 10.42%
Recommended ROE	**10.75%**	**9.25%**	**9.40%**

a. Proxy Group of Gas Companies

FCG witness Nelson selected six companies from the Value Line Investment Survey to include in the gas utility proxy group. The gas proxy group includes Atmos Energy Corp., New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., and Spire, Inc. The Intervenor Witnesses took no issue with FCG witness Nelson's selection of gas utilities for the proxy group and used the same proxy group for their respective cost of equity analyses.

b. Discounted Cash Flow (DCF) Model

The Discounted Cash Flow (DCF) cost of equity model is based on the theory that a stock's current price represents the present value of all expected future cash flows in the form of dividends discounted at the appropriate risk-adjusted rate of return. In its basic form, the DCF model is expressed as the dividend yield of a stock plus the expected long-term growth rate. Mathematically, the DCF model is expressed as ROE = (dividend ÷ stock price) + growth rate.

The differences between FCG witness Nelson's and the Intervenor Witnesses' DCF model results are primarily driven by differences in chosen growth rates, as well as witness Nelson's use of the quarterly compounding dividend yield. FCG witness Nelson used an average growth rate of 6.07 percent in her DCF analysis. FEA witness Walters used three different growth rates of 5.95 percent, 5.67 percent, and 4.35 percent in three variations of the DCF model. OPC witness Garrett used an analyst growth rate of 4.8 percent and a sustainable growth rate of 3.8 percent in two variations of the DCF model.

OPC witness Garrett's DCF results were 7.1 percent and 8.0 percent. We find that OPC witness Garrett's DCF model result of 7.1 percent is not reasonable because it uses the national GDP as the growth rate and does not reflect the growth rate of regulated natural gas utilities, and shall be given little weight. OPC witness Garrett also used a DCF model using analyst forecasts as the growth rate and obtained a result of 8.0 percent, but asserted that this result should not be considered at all. An objective review of FCG witness Nelson's DCF results established the average of her constant growth DCF model at 9.72 percent and the average of her quarterly growth DCF model at 9.86 percent. The average of the median and mean of FEA witness Walters' three variations of the DCF model were 9.2 percent, 9.11 percent, and 8.09 percent. The average of FCG and FEA witnesses' DCF Model results is 9.2 percent.

c. Capital Asset Pricing Model (CAPM)

The CAPM method of analysis to determine cost of equity is based upon the theory that the market-required rate of return for a security is equal to the risk-free rate plus a risk premium associated with the specific security. The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. Therefore, the CAPM assumes that investors require compensation only for systematic, or market, risk. Non-diversifiable (or systematic) risk is measured by the beta coefficient. 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 equity risk premium (ERP) expressed in this equation: ROE = risk-free rate + Beta × (market return – risk-free rate).

Consistent with our prior practices and the evidence presented in this case, we find the application of the market-based DCF Model and CAPM are the best methods to determine the cost of equity because both reflect market-based and utility financial data. The models are not disputed in this case. Rather, there was competing testimony offered by FCG and the Intervenors as to the underlying assumptions and use of the CAPM.

FCG Witness Nelson testified that his use of the CAPM results in the long-term arithmetic average historical return on the market of 12.33 percent as an appropriate alternate estimate of the expected market return. However, OPC and FEA offered testimony that countered FCG's CAPM results. OPC and FEA provided testimony that asserted FCG witness Nelson's CAPM results are unreasonably high due to her overestimation of the projected market return and ERP. The Intervenors countered FCG's testimony with:

- FEA witness Walters testified that FCG witness Nelson's use of the empirical CAPM utilized an ERP of 70 companies with exceedingly high growth rates, and growth rates for companies in the S&P 500 that are two times the projected growth of the U.S. economy.

- FEA witness Walters also testified that FCG witness Nelson's projected market required return of 14.64 percent in the CAPM is overstated and unreasonable, because FCG's use of the MI beta coefficient of 0.70 in the CAPM is questionable and subject to analyst bias in selecting the inputs to the model.

- FEA witness Walters further testified that he calculated nine different applications of the CAPM using a combination of three different beta estimates and three different ERP estimates. Based on these results, FEA recommended a CAPM return estimate of 9.4 percent.

- OPC witness Garrett testified that the appropriate CAPM yielded an ROE estimate of 7.9 percent. OPC witness Garrett also testified that FCG Witness Nelson's ERP estimate and sources used to support her estimates were not within the range of reasonableness.

The witnesses' results from the traditional CAPM were 10.12 to 12.94 percent for FCG, 7.9 percent for OPC, and a range of 7.34 to 10.97 percent for FEA. We find that FCG witness Nelson's highest CAPM results of 12.80 and 12.94 percent arising from her traditional CAPM are not supported. While we agree with the Intervenors that FCG's traditional CAPM analysis results in an ROE estimate that is too high, we are not persuaded by the ROE estimates offered by OPC and FEA, because those are too low. OPC witness Garrett's CAPM result of 7.9 percent is unreasonably low because he used a current risk-free rate, which is now stale, and an unreasonably low ERP estimate based on various publications of ERP surveys.

Likewise, we find that FEA witness Walters' use of the MI beta coefficient in his CAPM is questionable and subject to analyst bias, and that his use of Kroll's ERP and the results of the CAPM using that data are unreasonable. The average of the remaining results from FCG and FEA witnesses' CAPM analyses is 10.3 percent.

FCG witness Nelson argued that FCG's small size based on market capitalization as compared to the gas utilities in the proxy group supports a small size adjustment to increase the target ROE. The record evidence demonstrates FCG has a much higher equity ratio of 59.6 percent than the average of the gas proxy group of 47 percent. We find FCG's higher equity ratio and financial strength balance out any risk associated with its smaller size and a numerical adjustment is neither necessary nor reasonable.

3. Conclusion

After eliminating some of the witnesses' results produced by questionable assumptions and inputs used in the DCF and CAPM models as discussed above, the average of the witnesses' composite DCF model results (9.2 percent) and the composite CAPM results (10.3 percent) is 9.75 percent (10.3 + 9.2 = 19.5 ÷ 2 = 9.75). Both FCG witness Nelson and FEA witness Walters used similar forms of the risk premium model and obtained similar results. FCG witness Nelson's risk premium results were 9.73 percent and 9.80 percent, and witness Walters' results ranged from 9.27 percent to 10.42 percent. Consistent with our prior ROE determinations, we have selected an ROE target midpoint and accompanying range of 100 basis points.

We find the testimony and evidence supports a mid-point ROE of 9.50 percent with a range of plus or minus 100 basis points. While this result is slightly greater than the national average authorized ROE for gas utilities in 2022 of approximately 9.38 percent, we find this

ROE will enable FCG to generate the cash flow needed to meet its near term financial obligations, make the capital investments needed to maintain and expand its system, maintain sufficient levels of liquidity to fund unexpected events, and sustain confidence in Florida's regulatory environment among credit rating agencies and investors. Therefore, our ROE midpoint of 9.50 represents a reasonable middle ground between all of the models and recommendations presented.

Based on the analysis of the record evidence discussed above, we find the appropriate authorized ROE midpoint is 9.50 percent with a range of plus or minus 100 basis points.

G. Non-Utility Investments

At hearing, we approved a stipulation whereby all parties agreed that FCG does not have any non-utility investments and therefore, adjustments to the common equity balance were not required.

H. Weighted Average Cost of Capital (WACC)

1. Parties' Arguments

FCG argued the appropriate after-tax Weighted Average Cost of Capital (WACC) for the 2023 Test Year is 7.09 percent as presented in FCG witness Fuentes' recalculated revenue requirement. FCG witness Campbell asserted that FCG's proposed regulatory capital structure would produce a total WACC of 7.09 percent in the 2023 Test Year. Witness Campbell contended that a WACC of 7.09 percent is reasonable and reflects the benefit to customers of FCG's financial strength, including the benefit FCG receives from its parent, FPL. FCG argued the Intervenors' recommended WACCs are based on their proposed capital structure and midpoint ROE, which should be rejected for the reasons stated in the above discussion of the equity ratio and return on equity. FCG argued that for this reason the Intervenors' proposed WACCs should be rejected.

OPC witness Garrett recommended that we impute a capital structure for ratemaking purposes consisting of long-term 53.1 percent debt, and a 9.25 percent return on equity. This would result in a WACC of 5.75 percent. OPC argued that the three primary components of a company's WACC are the cost of debt, the cost of equity, and the capital structure. OPC argued the cost of capital is expressed as a weighted average because it is based upon a company's relative levels of debt and equity, as defined by the particular capital structure of that company. OPC argued pursuant to the standards set forth in *Hope* and *Bluefield*, financial integrity should be sufficient to attract capital on reasonable terms under a variety of market and economic conditions.

FEA did not specify an appropriate weighted average cost of capital to use in establishing FCG's projected test year revenue requirement. However, FEA recommended we adopt the cost of capital parameters proposed by FEA witness Walters, including a return on common equity of 9.40 percent and a common equity ratio of 50 percent, which would produce a weighted average cost of capital of approximately 5.95 percent.

2. Analysis

The WACC is an issue that incorporates the amounts and cost rates of the capital sources determined in other sections into a final WACC. The amounts and cost rates of the capital components are discussed above. In MFR Schedule G-3, FCG presented its requested projected test year capital structure based on a 13-month average as of December 31, 2023, consisting of common equity in the amount of $256,187,447 (59.6 percent), long-term debt in the amount of $153,552,333 (35.7 percent), and short-term debt in the amount of $20,141,146 (4.7 percent) as a percentage of investor supplied capital. In her rebuttal testimony, FCG witness Fuentes included revised projected 2023 test year cost of capital schedules, but the WACC did not change. FCG witness Campbell explained the ratios of FCG's investor supplied capital are based on the actual capital structure of FCG's parent company, FPL. When reconciled to FCG's rate base which includes customer deposits and deferred taxes, the ratios are reduced to 52.56 percent for common equity, 31.5 percent for long-term debt, and 4.13 percent for short-term debt.

OPC recommended reducing the amount of common equity in the projected capital structure and increasing the amount of long-term debt. In his testimony, OPC witness Garrett recommended we reject FCG's proposal, arguing it has the effect of increasing capital costs beyond a reasonable level for customers. OPC witness Schultz utilized witness Garrett's recommended capital structure in OPC's proposed calculations. To reflect OPC's recommended equity ratio of 46.9 in the capital structure, witness Schultz removed $54,573,294 from the common equity balance in FCG's projected capital structure and added $54,553,024 to the long-term debt balance and $20,269 to the short-term debt balance. OPC also recommended reducing the total rate base balance by $32,387,362 and making a corresponding adjustment to reduce the capital structure by the same amount pro-rata over all sources of capital.

FEA did not recommend a specific capital structure including all the capital component amounts or an overall WACC, only that the equity ratio should not exceed 50 percent.

As discussed above, the appropriate amount of: deferred taxes is $52,659,661 at zero cost; short-term debt is $19,730,996 at a cost rate of 1.78 percent; long-term debt is $150,425,423 at a cost rate of 4.28 percent; customer deposits is $3,710,465 at a cost rate of 2.64 percent; and common equity is $250,970,496 at a cost rate of 10.00 percent. Record evidence indicates that using the capital structure of FCG's parent, FPL, is reasonable, comparable to the equity ratios of other regulated gas utility companies in the gas proxy group, and consistent with prior Commission practice. Therefore, we agree with FCG that the appropriate capital structure consists of 59.60 percent common equity, 35.70 percent long-term debt, and 4.70 percent short-term debt as a percentage of investor sources.

3. Conclusion

To reconcile the capital structure with the approved rate base balance of $487,257,875, the appropriate adjustment is a pro rata decrease over all capital sources. After the reconciliation adjustment, the WACC is 6.44 percent.

The appropriate capital structure consists of 59.60 percent common equity, 35.70 percent long-term debt, and 4.70 percent short-term debt as a percentage of investor sources. Based on the proper components, amounts, and cost rates associated with the projected capital structure for the 13-month average test year ending December 31, 2023, as discussed above, the appropriate weighted average cost of capital for FCG for purposes of setting rates in this proceeding is 6.44 percent. The appropriate WACC is presented in Attachment No. 2, which is integrated and attached to this order.

VII. Net Operating Income

A. Purchased Gas Adjustment and Natural Gas Conservation Cost Recovery

At hearing, we approved a stipulation whereby all parties agreed that FCG has properly removed the purchased gas adjustment and natural gas conservation cost recovery revenues, expenses, and taxes other than income from the projected test year.

B. SAFE Investments

At hearing, we approved a stipulation whereby all parties agreed that FCG has made the appropriate adjustment to Net Operating Income to remove amounts associated with the transfer of SAFE investments as of December 31, 2022, from clause recovery to rate base.

C. Outside Service Costs

1. Parties' Arguments

FCG argued that transferring outside service costs incurred for clause dockets from base rates to respective cost recovery clause dockets is consistent with the cost-causation principle. FCG stated that by allowing this proposed method of recovery it will guarantee that ratepayers only pay for the actual cost incurred for outside services required to support the clause proceedings, subject to true-up. FCG asserted that they have made all appropriate adjustments to remove the outside service costs incurred for clause dockets from the projected test year operating revenues and operating expenses.

2. Analysis

FCG requested recovery of outside service costs incurred for clause dockets in respective cost recovery clause dockets instead of base rates. FCG witness Fuentes testified that this method is consistent with the cost causation principle and will ensure that customers are only paying for the actual costs incurred, subject to true-up. FCG made an estimate of $57,294 that is based upon the estimated amount of time FPL employees and external legal support will spend working on all of FCG's cost recovery clauses on an annual basis. The Company stated that if this proposal is accepted by the Commission, it will create a new master data system to track and record outside services for both FPL and external legal support in the appropriate cost recovery clause at the time the cost is incurred. FCG stated that, if approved, this new method will allow the amount recorded in each recovery clause to be based on actual time spent for each FPL employee and/or external legal support, and based on contracted rates not on allocation of costs.

FCG maintained it does not foresee a large increase in regulatory oversight in each of the applicable cost recovery clause dockets, and FCG proclaimed that the possible incremental regulatory oversight would be beneficial to customers by confirming that they only pay for the actual costs incurred. Even an incremental increase in regulatory oversight is something that should be carefully considered due to the potential complexities from creating additional regulatory oversight.

Similar to previous company requests to recover bad debt expense through clauses instead of base rates, this would require additional regulatory oversight. In Order No. PSC-10-0153-FOF-EI, we denied FPL's request to recover portions of bad debt through recovery clauses instead of base rates.[21] In that case, FCG acknowledged it would need to create additional regulatory oversight by developing a new master data system in order to track and record outside services in the appropriate cost recovery clauses for what FCG estimated to be immaterial expenses for each cost recovery clause. We do not find that FCG has provided a persuasive argument to change Commission practice.

3. Conclusion

We find that FCG shall continue to recover outside service costs incurred by clause dockets through base rates and not cost recovery clauses. As such, O&M expense shall be increased by $57,294.

D. Miscellaneous Revenues

1. Parties' Arguments

FCG stated that the appropriate amount of miscellaneous revenues is $1,896,516. The Company explained that this amount includes a reduction of $16,071 to correct for a forecasting error.

2. Analysis and Conclusion

In its initial filing, FCG reflected $1,912,587 of miscellaneous revenue. However, FCG witness DuBose stated that FCG inadvertently included $16,071 for forecasted billing adjustments that should have been removed from the projected 2023 test year operating revenues. None of the intervenors took a position on this issue nor did they have any adjustments. Aside from the Company's correction, no other adjustments are necessary. As such, we find for decreasing miscellaneous revenues from FCG's initial request by $16,071 to the appropriate amount of $1,896,516.

[21] Order No. PSC-10-0153-FOF-EI, issued March 17, 2010, in Docket No. 080677, *In re: Petition for increase in rates by Florida Power & Light Company,* Pg. 142-143.

E. Total Operating Revenues for the Projected Test Year

1. Parties' Arguments

FCG made no argument for this issue, but took the position that the appropriate amount of Total Operating Revenues is $64,724,868 for the 2023 projected test year.

As part of its argument that adjustments should be made with regard to the Company's customer and therm forecasts, OPC cited in its brief an excerpt from staff's cross examination of FCG witness Campbell. This excerpt included questions related to additional Company revenues in 2024 and 2025 resulting from FCG's expected growth in customers. OPC noted that witness Campbell stated he did not forecast the impact of this growth in customers but estimated that this growth would result in additional revenues of approximately $200,000 per year. Additionally, OPC noted FCG's witness admitted that the Company's customer and therm forecasts typically become progressively less reliable the further they are projected into the future.

2. Analysis

This is a fallout issue based on the resolution of other issues. Per our decisions in section I above, there are no recommended adjustments to FCG's forecasts of customers, therms, billing determinants, or revenue from the sales of gas at present rates for the 2023 projected test year. As discussed above, we agree with the Company that miscellaneous revenues at current rates for the projected test year shall be decreased by $16,071 to account for the Company's forecasting error, resulting in miscellaneous revenues for the projected test year totaling $1,896,516. This adjusted amount of Miscellaneous Revenues, when added to the Total Revenue from Sales of Gas at Current Rates of $62,828,352, results in projected Total Operating Revenues in the amount of $64,724,868 for the projected test year.

3. Conclusion

The Intervenors did not present testimony or evidence to disprove FCG's projected Total Operating Revenues for the projected test year. Therefore, we find that $64,724,868 is the appropriate level of total operating revenues for the 2023 projected test year.

F. Non-Utility Activities

At hearing, we approved a stipulation whereby all parties agreed that FCG has made the appropriate adjustments to remove all non-utility activities from operation expenses, including depreciation and amortization expense.

G. Salaries and Benefits

1. Parties' Arguments

FCG argued the appropriate amount of salaries and benefits to include in the Test Year is $14,803,183. FCG argued the reasonableness of salary and benefit expense is demonstrated by comparison to the relative comparative market.

OPC argued for reductions in base payroll, incentive compensation, benefits, payroll taxes, and other expenses.

2. Analysis

a. Salaries and Full Time Employees (FTEs)

OPC offered testimony that the number of full time employees (FTEs) is unreasonable because FCG's forecasts are overly optimistic compared to historical data. Witness Schultz testified that the employee complement of 187 FTEs is inappropriate and does not consider a vacancy factor, and recommended a head count of 173 FTEs. In 2021, actual payroll, excluding recovery clause costs for 2021, was $1,893,794 under budget over the actual of $13,126,569. Witness Schultz also recommended a $49,533 reduction to employee benefits.

FCG witness Slattery countered OPC's arguments and testified that in 2019 and 2020 actual head count exceeded the budgeted headcount to support the replacement of services and functions provided by its acquisition of Southern as well as growth in the business. FCG Witness Slattery testified FCG experienced hiring difficulties, which included limited availability of technical and engineering related labor; desirability of, and competition for, in-demand technology skills; fluctuations in the housing market; and the fiscal restraints the Company has placed on the competitiveness of its pay and benefits package. The witness also testified that there was a skilled labor shortage due in part to the COVID-19 pandemic, "the Great Resignation," and the rise in remote work, but that despite these factors, FCG put forth significant efforts in 2022 to fill the open positions. As of September 22, 2022, eight positions had been filled, which increased the employee headcount to 180 FTEs.

With regards to the vacancy factor, FCG witness Slattery testified that hiring costs and saving associated with vacancies were offset by the cost of overtime and the costs associated with recruiting, onboarding, and training new staff. Likewise, FCG witness Howard testified that FCG provided justification for the increased headcount and explained why each position was required. In broad terms, he asserted the new positions were created due to the physical expansion of FCG's system and enhancements to the customer information system (CIS) as well as the increase in customer count.

b. Incentive Compensation

OPC presented testimony that excessive incentive compensation should be reduced by $524,119, incentive compensation should be reduced by $398,746, and long-term incentive compensation should be reduced by $163,461. OPC witness Schultz pointed to three issues he had with the incentive compensation plan. First, FCG's amount of incentive compensation declined each year from 2019 to 2021, but for the projected 2023 test year FCG projected $1,772,728. Second, the total projected amount for 2023 is not known because performance and results of operation are not known and no goals are set. Third, since 2018, almost every employee received incentive compensation. He argued that despite the high percentage of employees receiving incentive compensation, FCG failed to meet some of its performance goals, and that half of the met goals were for financial performance, which provide benefits to shareholders and not customers. He further stated that FCG's incentive compensation plan is discretionary, and that is not what is customarily considered a short-term incentive plan. OPC recommended that $163,461 of the long-term plan costs be excluded and that $922,865 of short-term plan costs be excluded.

FCG Witness Slattery addressed incentive compensation in her rebuttal testimony and proposed a reduction of $505,222 associated with executive incentive compensation, noting that FCG removed parts of incentive compensation as required by our 2010 FPL Rate Case Order.[22] FCG Witness Slattery testified that the incentive compensation expenses are necessary and reasonable, and are an effective tool in "attracting, retaining, and engaging the required workforce, and play a significant role in delivering value to customers." She cited Order No. PSC-12-0179-FOF-EI in which we rejected OPC's recommendation to disallow all incentive compensation and allowed recovery of all of Gulf Power Company's employee cash compensation.[23]

Addressing FCG's incentive compensation compared to the market, FCG witness Slattery stated that FCG's plan is at or below market. If performance-based cash incentive compensation were eliminated, FCG employees would be compensated roughly 9.6-percent below the market median, and FCG would not be able to compete in the labor market in that scenario, leaving it unable to deliver on its commitments to its customers. FCG Witness Slattery further testified that if incentive compensation were to be removed, it would lead to a reduction in performance-based variable cash incentive compensation and an increase in base salary and other fixed-cost programs.

Witness Slattery testified that the reason a high percentage of FCG employees receive performance incentive compensation is to help develop a culture of employees committed to performance. Few employees who stay with FCG fail to meet expectations by the end of the performance period. With regard to company goals, she stated that they are soft goals and reassessed annually. She asserted that while FCG failed to meet some goals in 2020 and 2021,

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[22] Order No. PSC-10-0153-EI, issued March 17, 2010, n Docket No. 080677-EI, *In re: Petition for increase in rates by Florida Power & Light Company.*
[23] Order No. PSC-12-0179-FOF-EI, issued April 3, 2012, in Docket No. 110138-EI, *In re: Petition for increase in rates by Gulf Power Company.*

FCG's performance as of August 2022 exceeded expectations for most goals, and employee cash incentive payouts are expected to be similar to historic levels. Witness Slattery contended that the growth in performance-based cash incentive compensation cost correlates to the growth in head count and the growth in salaries.

C. Conclusion

Upon review of the testimony presented by FCG, we find FCG has adequately addressed concerns related to staffing levels and incentive compensation. Moreover, the market-based evaluation of FCG's total compensation further supports not making any further adjustments other than to decrease employee pension and benefits expense by $505,222 to recognize the Company's adjustment to remove executive incentive compensation.[24] Based on this adjustment, the appropriate amount of salaries and benefits to include in the projected test year is $14,803,183.

H. Affiliate Expenses

1. Parties' Arguments

FCG claimed that it has included the affiliate services that are necessary to run its business in the 2023 test year, as is consistent with historic practice. FCG stated that OPC recommended that $405,400 of costs allocated as part of FPL's Corporate Service Charges (CSC) should be excluded. FCG argued that these costs relate to executive incentive compensation, which have already been removed by FCG in its rebuttal adjustments explained in the previous section.

OPC claimed that FCG was unable to provide a comparison of affiliate costs included in the 2018 Settlement Agreement to the requested 2023 affiliate costs. OPC argued that the Company has $405,440 of costs that we disallowed in prior dockets. OPC also claimed that $29,576 of Supplemental Executive Retirement Plan (SERP) costs were included in Corporate Service Charges. These costs are considered excessive compensation, therefore OPC recommended they be disallowed.

2. Analysis and Conclusion

The Company's projected test year reflects affiliate expense of $2,982,225. As explained by FCG witness Fuentes, all costs associated with affiliate service provided by FPL are charged according to FPL's Cost Allocation Manual (CAM). As prescribed by FPL's CAM, affiliate expense associated with services provided by FPL to FCG are billed as a direct charge or allocated in FPL's CSC. Of the total affiliate expense in the projected test year, $1,257,227 are direct charges and $1,724,997 are billed through CSC.

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[24] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket 080317-EI, *In re: Petition for rate increase by Tampa Electric Company* and Order No. PSC-12-0357-PAA-WU, issued July 10, 2012, in Docket 100048-WU, *In re: Application for increase in water rates in Marion County by Sunshine Utilities of Central Florida, Inc.*

OPC witness Schultz testified that there were several concerns with affiliate expense in the projected test year. The first concern was that FCG was unable to provide a comparison of affiliate costs included in the 2018 Settlement Agreement to the requested 2023 affiliate costs. Second, OPC contended that FCG included $405,400 of costs related to incentive compensation that we have disallowed all or part of in prior dockets. Third, SERP costs in the amount of $29,576 were included in CSC. In its brief, OPC also added AMI O&M expense to its concerns related to affiliate expense. FCG argued it is under new ownership, and as such, any comparison to historic data would not be appropriate. OPC's concerns are addressed in the discussions of employee compensation above and pensions and benefits below. We find no further adjustments are warranted. Therefore, we find affiliate expense for the projected test year shall be $2,477,003.

I. Pensions and Post-Retirement Benefits Expenses

1. Parties' Arguments

FCG argued that no adjustments should be made to remove Supplemental Executive Retirement Plan (SERP) benefit expenses from the corporate service charges. This treatment is consistent with the adjustments made by FPL pursuant to the FPL 2010 Order.

As discussed in the previous section, OPC argued that affiliate SERP costs in the amount of $29,576 should be removed.

2. Analysis and Conclusion

FCG requested employee pensions and post-retirement benefits expense of $661,618. OPC witness Schultz testified that $29,576 of SERP costs included in pension and post-retirement benefits expense should be disallowed as those costs are considered to be excessive compensation. FCG witness Slattery stated that consistent with the FPL 2010 rate case order, no adjustments are necessary to remove SERP benefit expenses from the Corporate Services Charge (CSC).[25] In the FPL 2010 rate case order, we declined to adjust FPL's forecast for affiliate expense.

We find OPC's arguments for reducing SERP lack support and therefore are unpersuasive. We find FCG's request to be reasonable, and therefore, we find the appropriate amount of pensions and post-retirement benefits expense to include in the projected test year is $661,618.

[25] Order No. PSC-10-0153-EI, issued March 17, 2010, in Docket No. 080677-EI, In re: *Petition for increase in rates by Florida Power & Light Company.*

J. Injuries and Damages Expense

1. Parties' Arguments

FCG stated that its core values emphasize a commitment to safety. FCG goes on to explain that because of this emphasis on safety, the appropriate injuries and damages expense for the 2023 Test Year is $515,304.

FCG refuted claims by OPC witness Schultz that FCG's safety performance needs improvement as well as his recommendation that injuries and damages expense be reduced by $212,790. FCG stated that OPC's claims are without merit and should be rejected. FCG asserted that OPC's reliance on OSHA-recordable events is misplaced and that while they are a useful metric, they do not necessarily demonstrate overall workplace safety. FCG's main assertion was that OSHA-recordable events alone do not provide sufficient information as FCG encourages its staff to report all injuries regardless of severity. FCG stated that since its last rate case there have been no recorded incidents that OSHA flagged as "Serious Injuries or Fatalities," with most of FCG's OSHA-recordable incidents being of a less severe variety, like sprains and strains. FCG additionally stated that since 2019, the Company has never had more than three recordable incidents within a year. FCG also explained that the increase in the cost is the result of increases in insurance premiums across the industry and the reclassification of expenses. FCG then reiterated that the amount requested for injuries and damages expense is reasonable and should be approved.

OPC stated that injuries and damages expense doubled each year from 2019 to 2021. During that period, the cost increased from $111,135 to $243,888 to $552,519. OPC also stated that the Company requested $515,304. OPC stated that the increases, which took place under the ownership of FPL, are largely related to: insurance or reserve accruals to protect the service company against injuries and damages claims by employees or others, losses of such character not covered by insurance, and expenses incurred from settlements of such claims. It should be noted that in both 2020 and 2021, the Company failed to meet its goals for the number of OSHA-recordables (per 200,000 hours). OPC recommended using a three-year average for injuries and damages expense, a reduction of $212,790.

2. Analysis

FCG requested $515,304 for injuries and damages expense. OPC witness Schultz stated that the expense doubled each year from 2019 to 2021 from $111,135 to $243,888 to $552,519. He contended that FCG has a trend of safety concerns and that this has led to the increase in injuries and damage expense. He stated the number of OSHA-recordables were worse than FCG's goal in 2020 and 2021. Witness Schultz recommended a decrease of $212,790, leaving $302,514. This adjustment is based on the three-year average from 2019 to 2021.

FCG stated that OSHA-recordable events do not necessarily demonstrate overall workplace safety, or the severity of the injuries sustained. Witness Howard asserted that FCG has not recorded any incidents that OSHA flagged as serious injuries or fatalities and that most recorded incidents were minor injuries. FCG witness Howard testified that since 2019, FCG has not had over three OSHA-recordable incidents in a year and had none in 2019 and the first half of 2022. The main increases to injuries and damages expense come from two factors: increases in the cost of insurance and a reclassification of expense from Account 924 (Property Insurance) to Account 925 (Injuries and Damages) from 2020. In its brief, FCG explained the reclassification, stating that in 2020, certain liability expenses were incorrectly recorded in Account 924 and were subsequently reclassified to Account 925 in 2021.

3. Conclusion

We find FCG's justification adequately explains the increase in this expense and we do not find a need for any adjustments. We find injuries and damages expense in the amount of $515,304 in the projected test year is reasonable.

K. Insurance Expense

1. Parties' Arguments

FCG stated that the appropriate injuries and damages expense (Account 925) and property insurance expense (Account 924) for the 2023 Test Year are $515,304 and $503,407, respectively. FCG opined that these insurance costs are incurred by FCG to provide service to its customers and benefit customers by not leaving them with potential exposure to costs associated with injuries and damages, property damage, and vehicle accidents. The Company also mentioned the imprudence of foregoing such coverage.

FCG challenged OPC witness Schultz's assertion that insurance expense should be reduced by $9,431 to remove Directors & Officers Liability (DOL) Insurance because this expense provides no benefits to customers. The Company stated that DOL insurance is a necessary and reasonable expense for FCG to provide service to its customers, as it is essential to recruiting and retaining talented and competent leadership. FCG stated that because of the above-mentioned reasons, FCG's DOL insurance expense is appropriately included in the 2023 Test Year revenue requirements.

OPC stated that as DOL insurance protects the Company's officers and directors from lawsuits that arise from their own questionable decisions, and the lawsuits are generally brought by shareholders, the customers receive no benefit from this insurance; as DOL insurance offers no benefit to customers it should be disallowed completely. OPC argued that if we do not disallow this cost, we should at least remove 50 percent of the requested amount.

2. Analysis

FCG requested $503,407 for insurance expense. OPC recommended a disallowance of $9,431 associated with DOL insurance expense. OPC witness Schultz testified that DOL insurance is to protect directors and officers and the only claims that make DOL insurance necessary come from shareholders, not customers. Witness Schultz also testified that this issue has been addressed by this Commission in prior cases which determined that DOL insurance expense should be shared equally between customers and shareholders. OPC recommended that the full amount of DOL be removed. Witness Shultz stated that if all of DOL insurance expense is not disallowed, then there should be an equal sharing of the cost between shareholders and customers.

In rebuttal testimony, FCG witness Howard testified that DOL insurance plays an important part in attracting and retaining skilled leadership which does benefit customers. He claimed that without DOL insurance, it would be impossible for FCG to attract and retain experienced directors and officers.

By Order No. PSC-10-0131-FOF-EI, the Commission reaffirmed its prior decisions that DOL "has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it."[26] The Commission also recognized that "ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital."[27] Because both shareholders and ratepayers benefit from DOL, the Commission split the cost of insurance between both groups.

3. Conclusion

Consistent with our prior decisions, we find that ratepayers and shareholders should share the DOL expense. With a reduction of half of DOL insurance expense, insurance expense shall be decreased by $4,716. Thus, we find insurance expense of $498,691 in the projected test year.

L. Projected Contractor Cost

At hearing, we approved a stipulation whereby all parties agreed that yes the projected contractor cost is reasonable. FCG does not separately identify or track contractor costs on its books and records, or in its forecast. However, FCG does track outside services, which includes contractor costs. As reflected on page 4 of MFR E-6, the reasonable, appropriate, and justified Test Year expense for Account 923 (Outside Services Employed) is $3,993,307 (adjusted).

M. O&M Expenses Adjustment

At hearing, we approved a stipulation whereby all parties agreed that there is no adjustment needed to the projected test year O&M expenses to reflect changes to the non-labor trend factors for inflation and customer growth.

[26] Order No. PSC-10-0131-FOF-EI, issued March 5, 2010, at p. 99, in Docket No. 090079-EI, *In re: Petition for increase in rates by Progress Energy Florida, Inc.*
[27] *Id.*

N. Storm Damage Reserve

1. Parties' Arguments

FCG argued that its current storm reserve was authorized in the 2018 Settlement Agreement, and the storm reserve could be revisited in the future if the reserve amount of $800,000 was exceeded. As of December 31, 2022, the Company's reserve balance was $205,415, thus it was unnecessary to reevaluate. Additionally, FCG argued that it submitted a Storm Damage Self-Insurance Reserve Study (Reserve Study) as required by Rule 25-7.0143, F.A.C., which concluded the storm reserve mechanism should be continued at its current levels.

OPC argued the storm reserve at present was adequately funded over the last 46 months, FCG had only charged costs against the reserve for two storms totaling $58,127. This resulted in an estimated annual average cost of $15,164. Given the current $162,290 reserve balance as of March 31, 2022, OPC argued that the storm reserve was sufficient for more than 10 years if costs were incurred at historic levels. OPC also argued that the Company's Reserve Study estimated the annual storm cost to be $190,000. OPC argued that the annual accrual of $57,500 should be discontinued as of January 1, 2023.

2. Analysis

FCG witness Campbell testified that the Company was authorized to implement a storm reserve as a part its 2018 Settlement Agreement, setting the annual accrual at $57,500 and a target reserve of $800,000. Witness Campbell testified that the 2018 Settlement Agreement established that FCG's storm related costs could be recovered consistent with Rule 25-6.0143, F.A.C., which is this Commission's storm rule applicable to electric utilities. We have since adopted Rule 25-7.0143, F.A.C., which is specific to gas utilities. This rule allows the establishment of a storm reserve account and outlines the types of storm related costs that an investor-owned natural gas utility can charge to the storm reserve. Witness Campbell testified that the Company is proposing to calculate and recover any storm related costs consistent with Rule 25-7.0143, F.A.C. However, FCG is not requesting any changes to the annual accrual or target reserve amounts.

In support of its argument that the storm reserve was adequately funded and OPC argued that the annual accrual of $57,500 should be discontinued, OPC witness Schultz testified that the Company's storm reserve balance was $162,290 as of March 31, 2022. He stated that over a period of 46 months, $58,127 had been charged against the reserve for two storms, the largest cost being $48,626 in 2020. Witness Schultz calculated that over the 46 month period, the $58,127 amount charged to the reserve averaged $1,264 a month or $15,164 annually. Therefore, FCG could charge $15,164 to the storm reserve every year for more than 10 years before the storm reserve was fully depleted.

In rebuttal, FCG witness Howard testified that per Commission Rule 25-7.0143, F.A.C., FCG had retained an independent, third-party consultant to prepare its Reserve Study and that the Reserve Study had found that continuing the storm reserve mechanism at a target of $800,000 was reasonable and appropriate considering the potential for future storms.

Furthermore, witness Howard testified that witness Schultz instead used "a few periods of historical data to base his entire conclusion that the current Storm Damage Reserve balance is adequate for future periods." Witness Howard asserted that witness Schultz's testimony ignored the purpose of the Commission-required Reserve Study and only used select storm data as a predictor of future storm damage to the Company's system. Witness Howard also testified that Florida is a hurricane-prone state, and FCG must plan and prepare for storms that may impact its service areas and facilities. Finally, OPC witness Schultz's recommendation to reduce the storm reserve by almost 75 percent was based on limited historical storm damage data and is not persuasive.

Having reviewed the conclusions of the Reserve Study, we find the storm reserve mechanism shall be continued at a target of $800,000, as approved in the 2018 Settlement Agreement. The historic storm data laid out by witness Schultz was limited in scope, only examining a 46-month period. Utilizing a 46-month period of data to predict future storm damage costs over the next ten years is not a sufficient basis. As a part of the Reserve Study's analysis, hurricane data from 1900 to 2017 was used, as well as information from other sources such as the National Oceanic and Atmospheric Administration. The Reserve Study estimated that the Company's expected annual cost due to storm damage was $190,000, although the annual cost could be as high as $2,500,000, compared to $15,164 as calculated by witness Schultz. Thus, the Reserve Study relied on a more expansive amount of data to reach its conclusions, which supported the reserve target of $800,000.

3. Conclusion

We are not persuaded by OPC that FCG's previously approved storm reserve mechanism should be discontinued or modifications made to the annual storm damage accrual and target reserve amounts. Further, if the Company's storm damage accrual and target reserve amounts remain in place as approved in the 2018 Settlement Agreement, there is no incremental increase in cost to customers. We approve the continuation of FCG's Storm Damage Reserve provision as included in the 2018 Settlement Agreement, which is consistent with Commission Rule 25-7.0143, F.A.C. No change shall be made to either the annual storm damage accrual of $57,500 or the target reserve amount of $800,000.

O. Parent Debt Adjustment (PDA)

1. Parties' Arguments

FCG witness Campbell testified that FCG has received 100 percent of its debt and equity financing from FPL's pool of funds which was available based on FPL's capital structure. Thus, a parent debt adjustment is not applicable in this case as the parent company, FPL, holds a lower percentage of debt in its capital structure than FCG, and no additional interest expense tax benefit exists at the parent company level. Furthermore, FCG has proposed a 2023 test year financing capital structure equal to the capital structure of FCG's parent which consists of 59.6 percent common equity and 40.4 percent debt as a percentage of investor sources of funds.

OPC argued this Commission has Rule 25-14.004, F.A.C. (Parent Debt Adjustment or PDA Rule) that has not been waived pursuant to Section 120.542, F. S., which mandates the required application of the PDA Rule unless the utility rebuts the presumption that debt of the parent may be invested in the equity of the subsidiary. OPC further argued that the overwhelming evidence is that debt is affirmatively shown to be embedded in FPL's investment in FCG and Federal income tax expense should be reduced by $382,452.

2. Analysis

The parent debt adjustment provides that the income tax expense of a regulated utility will be adjusted to reflect the tax benefit of the interest expense of the parent company where the parent company's debt may be invested in the equity of the regulated utility and both join in the filing of a consolidated income tax return.

NextEra Energy transferred FCG to FPL on July 29, 2018. Upon acquisition by FPL, there was no significant change in FCG's total per book capital structure value as inherited from Southern Gas Company, on a Commission-regulated basis. FCG has proposed a 2023 test year capital structure equal to the capital structure of FPL, which consists of investor sources of funds of 59.6 percent common equity and 40.4 percent debt. Additionally, FCG does not issue its own debt or equity in the marketplace. Because FCG does not issue its own debt, there is no double leverage. Because FCG does not issue its own debt or equity in the marketplace, it is reasonable to allocate FPL's investor sources of funds, debt and equity, to FCG for the purpose of setting FCG's rates. This approach recognizes that FPL's investor sources of funds are FCG's investor sources of funds, and therefore, the debt of FPL is not invested in the equity of FCG.

3. Conclusion

Because the investor sources of funds, and in essence, the capital structures, are one and the same, the debt of FPL is not invested in the equity of FCG and we find a parent debt adjustment is neither necessary nor appropriate under the PDA Rule.

P. Rate Case Expense

1. Parties' Arguments

FCG stated that an update to its estimated Rate Case Expense reflected a reduction in rate case expense of $0.1 million from the original estimate $1.9 million. The Company stated that consistent with its 2018 Settlement Agreement, it requested a four-year amortization period for Rate Case Expense, resulting in an annual amortized amount of $470,209. FCG pointed out that no parties opposed the four-year amortization period.

FCG opined that the primary driver of Rate Case Expense is the amount of work involved to litigate the case. FCG stated that it took a bottom-up approach to estimate the work involved to prepare, file, and litigate. The Company emphasized the amount of work involved with a rate case is due to factors largely out of the control of the Company.

FCG asserted that its decision to include FPL affiliate support was not to replace FCG's in-house resources, but instead to support a wide array of services necessary for a rate case. As a result, OPC witness Schultz's and FEA witness Collins' recommendations to limit the amount of Rate Case Expense is unsupported and without merit.

OPC stated that the test year costs have increased by $769,350 or 62.97 percent over the costs from FCG's previous rate case. OPC stated that while the scope of the study has increased, the requested amount is still excessive. OPC asserted that the $1,564,981 attributed to FPL replacement cost is unwarranted. OPC pointed out that these costs are higher than the benchmark Rate Case Expense of $1,476,260 applicable to the previous rate case. OPC stated an additional concern that the Company failed to take advantage of the Proposed Agency Action method, which burdened customers and benefited shareholders.

FEA witness Collins testified that the Rate Case Expense is over $700,000 more and 63 percent higher than expenses for FCG's previous rate case. He also asserted that the increase was not justified. FEA witness Collins stated that the lions-share of costs come from FPL's affiliate support; however, FCG does not demonstrate what support FPL provided or why this level of support was not needed in earlier rate cases. FEA witness Collins argued that we should limit FCG's rate case expense to previously approved amounts with an adjustment for inflation or $1.427 million. FEA stated that this would lower amortization expense by approximately $141,000 and lower the deferred Rate Case Expense in rate base by approximately $494,000. FIPUG joined the argument of FEA.

2. <u>Analysis and Conclusion</u>

FCG's initial filing included Rate Case Expenses of $1,991,116. FCG stated OPC's and FEA's arguments are without merit and unreasonable due to the nature of the costs associated with a fully litigated rate case. Through discovery, FCG updated the amount of Rate Case Expense, lowering the total amount of Rate Case Expense by $110,280, resulting in the updated amount of $1,880,836.

We have examined the requested actual and estimated expenses, along with supporting documentation, and find these expenses are reasonable for a rate case on the hearing track. FCG also requested a four-year amortization period. The four-year amortization period requested by FCG is not disputed by any of the intervenors, and we find it is reasonable. The appropriate annual amount of Rate Case Expense is $470,209. The appropriate amortization period is four years.

Q. <u>Uncollectible Accounts and Bad Debt</u>

At the hearing, we approved a stipulation whereby all parties agreed that no adjustment shall be made to Uncollectible Accounts for Bad Debt in the Revenue Expansion Factor.

R. O&M Expenses

1. Parties' Arguments

FCG's O&M expenses have increased by $5.8 million in the 2023 Test Year revenue requirement. FCG stated that approximately $2.4 million of the increase in operating costs is attributable to inflation. The remainder of the additional increase is due to customer growth, system expansion, increased damage prevention efforts, and implementation of certain technologies and initiatives that are necessary to continue to provide safe and reliable natural gas service.

OPC argued that it would be inappropriate for customers to pay for the experimental AMI program, considering FCG was not able to provide proof of how FCG customers would benefit from the program. OPC also noted that even though FCG claimed there would be costs savings, FCG was unable to support this claim.

2. Analysis and Conclusion

This issue is determined by our findings concerning other issues. Based on prior findings, the appropriate amount of projected test year O&M expense is $25,497,650.

S. Taxes Other Than Income (TOTI)

1. Parties' Arguments

FCG stated that because OPC's recommended adjustment to head count for the 2023 Test Year should be rejected, OPC's flow through adjustment (payroll tax) to Taxes Other Than Income Taxes should also be rejected.

OPC witness Schultz addressed this issue in his testimony and exhibits. The total amount of Taxes Other than Income should be reduced to no more than $6,263,843, after the payroll tax adjustment of $122,767.

2. Analysis

In MFR Schedule G-6, FCG states that property tax was projected by multiplying a composite millage rate of 1.8 percent by the net plant at year end. During discovery, FCG provided a more detailed calculation of the methodology used to estimate property taxes. The Company additionally provided updated property tax expense for 2022, which reflected a $1.1 million disparity between the actual and projected expense for 2022. We find that this large of a disparity warrants an adjustment to update the Company's estimated property tax expense to include the actual data for 2022. Using FCG's methodology, we included the actual taxable value and composite tax rate from 2022 to recalculate the estimated 2023 property tax expense. This results in a decrease of $510,886.

3. Conclusion

Based on our findings in previous issues, additional corresponding adjustments to TOTI are necessary. An adjustment to Load Enhancement Services (LES) revenue in section I results in an increase of $777 for corresponding regulatory assessment fees (RAFs). A reduction to forecasted miscellaneous revenue in Section IV results in a decrease of $80 for corresponding RAFs. A reduction to incentive compensation, also in Section IV, results in a corresponding reduction of $32,995 to payroll taxes. Therefore, we find that TOTI be reduced by a total of $543,184. Accordingly, we find the appropriate amount of TOTI for the projected test year is $5,843,427.

T. Test Year Income Tax Expense

1. Parties' Arguments

FCG stated that the appropriate amount of Income Tax Expense for the projected test year is $1,804,203. FCG noted that OPC recommended an adjustment to increase Income Tax Expense for the projected test year by $1.4 million, as reflected in OPC witness Schultz's testimony. FCG argued that OPC's recommended increase is based on the proposed adjustments to net operating income, which should be rejected, as addressed in previous issues.

OPC stated that the appropriate amount of Income Tax Expense is no more than $241,372, as addressed by OPC witness Schultz. OPC's recommended amount of Income Tax Expense does not include $1,530,280 of deferred income tax as reflected in witness Schultz's Exhibit 46.

2. Analysis and Conclusion

Based on our findings in previous issues, the appropriate amount of projected test year Income Tax Expense, including current and deferred income taxes and interest synchronization, is $1,934,574, as reflected in Table 3 below.

Table 3
Adjusted Income Tax Expense

MFR Amount Requested	$1,632,690
Adjustments:	
Interest Synchronization Adjustment	$6,381
Fall-Out Adj Federal Income Taxes	$231,378
Fall-Out Adj State Income Taxes	$64,126
Total Adjustments	$301,884
Adjusted Amount	$1,934,574

U. Operating Expenses

1. Parties' Arguments

FCG Stated that OPC's recommended reduction to the Total Operating Expenses is based on OPC witness Schultz's proposed adjustments to the individual components of net operating income, which are addressed in section VII.

OPC witness Schultz addressed this issue in his testimony and exhibits including, but not limited to, Exhibit 46, Schedule C. Total Operating Expenses should be reduced to no more than $49,398,824.

2. Analysis and Conclusion

Based on our findings in previous issues regarding net operating income, the appropriate amount of Total Operating Expenses for the projected test year is $50,592,224.

V. Net Operating Income

1. Parties' Arguments

FCG argued that OPC's recommended increase to Net Operating Income is based on OPC witness Schultz's proposed adjustments to the individual components of net operating income, which should be rejected for the reasons stated in previous issues.

OPC stated that Net Operating Income should be increased to at least $15,342,115. OPC also claimed that a credit should be reflected to prevent a double recovery of the plant cost for the LNG facility because revenue projections are understated, and the Company has already recovered $11,596,631 from ratepayers for the unused facility.

2. Analysis and Conclusion

Based on our findings in previous issues, the appropriate amount of Net Operating Income for the projected test year is $14,132,644.

VIII. Revenue Requirements

A. Revenue Expansion Factor and Net Operating Income Multiplier

At hearing, we approved a stipulation whereby all parties agreed that, as reflected in MFR G-4, the revenue expansion factor and net operating income multiplier for the 2023 projected test year are 73.9255 and 1.3527, respectively.

B. Annual Operating Revenue Increase

1. Parties' Arguments

FCG requested a rate plan with a total base rate revenue increase of $28.3 million based on the projected 2023 test year. This amount included an incremental base rate revenue requirement of $18.8 million, a previously approved increase of $3.8 million for the LNG facility, and $5.7 million to transfer the SAFE investments from clause recovery to base rates. FCG argued that the proposed four-year rate plan and incremental increase of $18.8 million would provide rate stability and certainty to customers, as such providing customers with savings and benefits lasting all four years.

FCG stated that it has earned below the bottom of the current authorized ROE range since the previous rate case and without base rate relief FCG will continue to earn below the current authorized ROE range. By FCG not earning in the authorized ROE range, FCG has not been fully recovering its reasonable and prudent costs of providing service to its customers. FCG stated that inflation, interest rates, capital costs, and overall market risk are not only higher since its last base rate case, but also greater than since FCG filed this base rate case on May 31, 2022.

OPC proposed a total base revenue increase of no more than $4,805,981, based on OPC witness recommended adjustments; FCG asserted that those recommended adjustments should not be considered based on explanations provided above. FCG asserted that the recommended increase by OPC would not allow FCG to earn at the bottom end of its current authorized ROE range and therefore would not allow FCG to earn within the proposed 2023 ROE range.

OPC stated that the base rate revenue increase should be no more than $4,805,981. OPC argued that the increase should be reduced due to the impact of revenue projections being understated and to reflect that the Company already recovered over $11,596,631 from customers for the LNG facility.

2. Analysis and Conclusion

Based on our findings above, the appropriate total annual operating revenue increase for the projected test year is $23,308,073. This amount includes an incremental increase of $14,149,121 and revenue associated with the transfer of SAFE investments and the LNG facility, as reflected Table 4 below.

Table 4
Annual Operating Revenue Increase

Operating Revenue Increase	$23,308,073
LNG Revenue	(3,828,493)
Transfer of SAFE Investments	(5,330,459)
Incremental Revenue Increase	$14,149,121

IX. Cost of Service and Rate Design

A. Cost of Service Study (COSS)

1. Parties' Arguments

FCG witness DuBose testified that the purpose of the COSS is to allocate the Company's costs among the different rate schedules based on cost causation principles. When developing a COSS, costs are first grouped by function (such as distribution or production), then costs are classified into the four main classifications: customer, commodity, demand, and revenue. Capacity costs include mains, regulator stations, and LNG storage. Customer costs include meters, house regulators, and services. Capacity and customer-related costs represent the majority of the total cost of service. Finally, there is an allocation of costs to the various rate classes based upon allocation factors. FCG argued its COSS is appropriate and consistent with the methodologies used by the Company in prior rate cases, and follows the presentation format of the prescribed MFR forms and schedules. FCG further argued that FEA witness Collins' proposed COSS would significantly shift costs from C&I classes to the residential customer classes if adopted.

FEA witness Collins testified that FCG's Class Cost of Service Study (CCOSS) is not appropriate and does not accurately reflect class cost causation because it uses the Peak and Average (P&A) method to allocate the cost of mains to customer classes and also fails to allocate any distribution mains costs on a customer basis. FEA asserted in its brief that the COSS provided by its witness better reflects how capacity costs are incurred, which more accurately reflects cost causation.

FEA further argued that FCG's cost of service study is flawed because: (1) it does not reflect cost causation; (2) FCG's P&A method is not a traditional P&A method; and (3) FCG's P&A method improperly allocated the costs of distribution mains to customer classes primarily on a volumetric basis and fails to classify and allocate any distribution mains costs on a customer basis. FEA contended that in order to correct these flaws, the Company should classify mains on both a demand and customer basis. FIPUG joined the position of FEA.

2. Analysis

FCG contended that the primary difference between its proposed COSS and the COSS proposed by FEA is that the Company used the P&A methodology, whereas witness Collins proposed allocating distribution mains based on design day demand and number of customers. FCG further asserted that witness Collins' proposal is essentially a minimum distribution system allocation. FCG explained that FEA's proposal related to design day may be appropriate for a utility located in a colder climate where winter peaks occur due to residential gas heating load. FCG, however, serves 49 percent of its customers in Miami, and therefore FCG's system is not as peak-sensitive as a gas utility in a colder climate.

Additionally, FCG stated that although residential customers make up 93 percent of its customers, residential customers flow 14 percent of the gas while C&I customers flow 86 percent of the gas on FCG's system on an annual basis. FCG asserted that the allocation method proposed by FEA would inappropriately shift costs away from the C&I customers who use FCG's system the most during the year to residential customers who use it the least. FCG argued FEA's proposal does not account for the actual utilization of the mains by different classes of customers, with C&I utilization over six times that of residential customers. FCG argued that despite that, FEA witness Collins' proposal would allocate 70 percent of the total revenue requirements to the residential customers, while only 29 percent would be assigned to the C&I classes.

FCG further noted that the Company's COSS assigns 37 percent of costs to residential customers and 62 percent to the C&I classes. FCG argues that its proposed cost allocation methodology better reflects how customers use FCG's system than FEA's proposed methodology and is more consistent with cost causation theory, considering that the actual usage of the system by residential classes is 14 percent and the actual usage of the system by C&I customer classes is 86 percent. Finally, FCG argued that FEA also overlooks that the P&A cost allocation methodology has been widely used by investor-owned natural gas utilities in Florida, including FCG, Peoples Gas System, and Florida Public Utilities.

FEA emphasized in its brief that a fundamental question when selecting a COSS is whether the methodology reflects cost causation. Accordingly, FEA witness Collins testified that when a gas utility installs a new distribution main to expand capacity on its system, it must consider customers' demand on a system peak day, or design day, and the number of customers being served. Thus, FEA concluded, the costs the utility incurs to provide service are driven by peak day demand and the number of customers. FEA concluded that FCG's proposed COSS is inconsistent with cost allocation since it fails to allocate costs based on how they are incurred.

FEA witness Collins further argued that, based on his experience, in a traditional P&A cost of service study, capacity class allocators are determined by each class's contribution to the system design day demand, weighted by (1 - system load factor) and by each class's contribution to system annual usage, weighted by the system load factor. Witness Collins notes that instead of this methodology, FCG based the peak allocator on the monthly maximum volume of a class in the test year. Witness Collins contended that by using the sum of 13 months of volumes for its class P&A allocators (12 actual monthly usages plus the maximum monthly volumes), FCG is essentially allocating capacity-related costs on annual usage and not the traditional P&A method.

We reviewed FCG's three prior rate cases in 2017, 2003, and 2000 to determine how the capacity costs were allocated to the rate classes. In all three rate cases, FCG proposed and we approved the P&A method, consistent with the allocation of capacity-related costs in the instant case. We agree with FCG's position that the Company used the same cost classification methodology as in its previous three rate cases. In addition, FEA provided no support to justify their assertion that a traditional P&A COSS employs a different allocation than FCG's proposed P&A methodology.

Witness Collins stated that FCG designs its system to meet the design day demands of its customer classes and must allocate some of its distribution costs based on design day demand. However, witness DuBose argued that while design day may be a factor in system design, the guidance provided by the National Association of Regulatory Utility Commissioners Gas Distribution Rate Design Manual acknowledges that there are other factors to consider when allocating distribution costs that are unique to each gas utility. Witness DuBose further stated that witness Collins' proposal related to design day could be appropriate for a utility located in a colder climate that builds and operates its system to serve high and extended winter peaks that occur due to increased residential gas heating load. While we acknowledge that there are different methodologies to allocate costs, we find that FCG provided a reasonable basis for continuing the P&A method, as proposed, for allocating capacity-related costs.

Witness DuBose testified that although residential customers make up 93 percent of FCG's customers, the residential customers flow only 14 percent of the gas on an annual basis while commercial and industrial (C&I) customers flow 86 percent of the gas. FCG's COSS methodology assigns 37 percent of the cost to residential customers and 62 percent to the C&I customers. Witness Collins allocated 70 percent of the total revenue requirement to residential customers and only 29 percent to C&I customers. We find that FCG's P&A method produces a cost allocation that more closely matches how customers utilize the distribution system. FEA's proposed method, on the other hand, unduly shifts costs from C&I customers to residential customers.

3. Conclusion

Based on review of the record, FCG's proposed cost of service study is appropriate and is hereby approved for all regulatory purposes until base rates are reset in FCG's next general base rate proceeding.

B. Revenue Increase Allocation Amongst Rate Classes

1. Parties' Arguments

FCG argued in its brief that the Company allocated the proposed revenues by rate class to improve parity among the rate classes as much as possible, while following our practice of gradualism and considering the competitive nature of the natural gas industry. FCG further asserted that the Company's proposed rates practice gradualism, because no class would receive an increase greater than 1.5 times the system average increase in total operating revenues, including adjustment clauses.

Moreover, FCG argued that it is appropriate to consider the competitive nature of the natural gas industry when designing rates, to mitigate the potential for fuel switching and bypass. FCG contended that moving all rate classes to parity, even when applying gradualism, could result in a disproportionate increase to certain large C&I customer classes, which could make fuel switching or bypass more economical than continuing to receive service from the Company. FCG stated that the Company slightly reduced the proposed increase to rate classes GS-120K and GS-1250K to address the potential for fuel switching and bypass.

Finally, FCG argued that FEA's proposed revenue allocation should be rejected, because it relies on FEA's proposed cost of service study methodology, as discussed above, which is inconsistent with Commission practice and not reflective of how FCG operates and provides service to its customers.

In its brief, FEA stated that the Company's class revenue allocation should be distributed to the rate classes using the results of witness Collins' cost of service study, because the Company's proposed cost of service study does not accurately reflect class cost causation. FEA further argued that witness Collins' class revenue allocation proposal moves each class's revenue increase to no greater than 1.5 times the system average increase, with no class receiving a rate decrease. FIPUG joined the arguments of FEA.

2. <u>Analysis</u>

Witness DuBose testified that FCG proposed revenues by rate class to improve parity among the rate classes to the greatest extent possible, while applying gradualism and considering the competitive nature of the natural gas industry. Parity is calculated by dividing the class rate of return (ROR) by the system ROR. A rate class with a parity index of 100 percent earns the same ROR as the system average and is at parity. A rate class with a parity index of less than 100 percent is below parity; a rate class above 100 percent is above parity. The ROR by rate class shows which classes are over- or under-earning relative to the system ROR, or stated differently, which class is covering their cost to serve and which class is not. Witness DuBose stated that FCG's COSS shows that parity indices vary by rate class, with some class indices above parity while others fall below parity. Assessing parity at present rates provides a starting point in allocating any increase in revenue requirements.

Gradualism is a concept that is applied to prevent a class from receiving an overly-large rate increase. When a rate increase limit is imposed on a rate class, the remaining classes will have to absorb that difference. In previous electric and natural gas rate cases, we have applied the policy of limiting rate increases in total operating revenues for an individual rate class to no greater than 1.5 times the system average increase, and that no rate class receives a revenue decrease.

As witness DuBose explained, the allocation of any revenue requirement increase should be assessed in terms of its impact on the ROR and parity index for the respective rate class. Witness DuBose testified that FCG is requesting a 44 percent increase in total revenues for the 2023 test year. Under our guideline of gradualism, any increase to a rate class would be limited to 66 percent, or 1.5 times the proposed system increase of 44 percent. Witness DuBose's calculations show that under FCG's proposed increase, no class would receive more than a 56 percent increase, including the transfer of SAFE revenue requirements from clause to base rates and the addition of the previously-approved LNG project.

MFR Schedule H-1, with RSAM, page 2 of 6, similarly shows that no class would receive an increase of more than 56 percent, with percent increases ranging from 34 percent to 56 percent. The same MFR Schedule also shows parity indexes at present and proposed rates. With the exception of the GS-120K rate class, which is discussed below, FCG has proposed revenues by rate class that improve parity to the greatest extent possible, as asserted by witness DuBose.

With respect to large C&I customers, witness DuBose explained that if natural gas service becomes uneconomical, large C&I customers can bypass FCG's system or locate their business outside of FCG's service territory or even the state of Florida. Therefore, to address the potential for fuel switching and bypass, FCG slightly reduced the proposed increases to rate classes GS-120K and GS-1250K. Rate class GS-120K is available to non-residential customers using between 120,000 and 1,249,999 therms per year; rate class GS-1250K is available to non-residential customers using between 1,250,000 and 10,999,999 therms per year. We agree with FCG's approach to consider the risk of large C&I customers choosing an alternate fuel supply or leaving FCG's service area, resulting in a loss of revenues and load. The retention of large C&I customers benefits the general body of ratepayers as their revenues contribute to FCG's fixed costs.

Witness Collins does not agree with the Company's class revenue allocation and asserted that FCG's COSS does not accurately reflect class cost causation and that FEA's COSS should be used to allocate the increase to the rate classes. Witness Collins did not testify that FCG proposed an increase greater than 1.5 times to any rate classes, and FEA only objected to FCG's COSS methodology.

3. Conclusion

Each rate class's COSS determines the allocation of any revenue requirements increase for each rate class. Therefore, differing COSS methodologies such as those proposed by FCG and FEA result in different increase allocations to the rate classes. In rebuttal testimony, witness DuBose summarized the difference between FCG and FEA's proposed revenue increase allocations, based in their respective COSS. FEA's proposed revenue increase to the residential RS-1 and RS-100 rate classes is 66.64 percent, while for the commercial rate classes it is 24.81 percent. We do not believe that FEA's proposed increases provide a balanced approach.

Based on the foregoing, and considering prior Commission practice of using gradualism to allocate an approved increase to the rate classes, we are persuaded by FCG's proposed allocation of the rate increase as shown by the testimony of witness DuBose. FCG's proposed revenue increase to the rate classes limits the increase in total revenues to any rate class to 1.5 times the system increase, reflecting our guidelines on gradualism and improving parity among the rate classes.

C. Proposed Customer Charges

1. Parties' Arguments

FCG did not provide an argument, but adopted the position that the appropriate customer charges are those shown in 2023 Test Year MFRs E-2 and H-1 (1 of 2).

2. Analysis and Conclusion

We find the customer charges discussed here, in combination with the per therm distribution charges and the demand charges discussed below, are designed to allow the

Company to recover the total Commission-approved revenue requirement. Further, we approved above both the Company's proposed cost of service methodology and the allocation of the revenue increase to rate classes. The customer charges reflect the appropriate revenue requirement and cost of service methodology; therefore, proposed charges provided in the tariffs in Attachment 6 are approved.

D. Distribution Charges

1. Parties' Arguments

FCG did not provide an argument but adopted the position that the appropriate per therm Distribution Charges are those shown in 2023 Test Year MFRs E-2 and H-1 (1 of 2).

2. Analysis and Conclusion

We have reviewed the Company's revised cost of service filing and it reflects the Commission-approved total Company revenue requirement. Further, we approved above the Company's proposed cost of service methodology and the allocation of the revenue increase to rate classes. The proposed per therm distribution charges reflect the approved revenue requirements and cost of service methodology; therefore, the proposed charges provided in the tariffs in Attachment 6 are approved.

E. Demand Charges

1. Parties' Arguments

FCG did not provide an argument, but took the position that the appropriate Demand Charges are those shown in 2023 Test Year MFRs E-2 and H-1 (1 of 2).

2. Analysis and Conclusion

We have reviewed the Company's revised cost of service filing and it reflects the Commission-approved total Company revenue requirement. Further, we approved above the Company's proposed cost of service methodology and the allocation of the revenue increase to rate classes. The proposed demand charges reflect the approved revenue requirements and cost of service methodology; therefore, the proposed charges provided in the tariffs in Attachment 6 are hereby approved.

F. Connect and Reconnection Charges

At hearing, we approved a stipulation whereby all parties agreed that the appropriate service, connect, and reconnection charges are those shown in 2023 Test Year MFR H-1 (2 of 2).

G. Transportation Customer Charge Application to Third Party Suppliers

At hearing, we approved a stipulation whereby all parties agreed that the appropriate per transportation customer charge applicable to Third Party Suppliers is shown in 2023 Test Year MFRs E-2 and H-1 (1 of 2).

H. Effective Date for Revised Rates and Charges

1. Parties' Arguments

FCG's filing requested a February 1, 2023 effective date for new base rates.

OPC took the position that the effective date of FCG's revised rates and charges should allow for time for implementation promptly after our final Order in this matter. FIPUG adopted the position of OPC.

2. Analysis and Conclusion

FCG provided a notification of the proposed rate increase to its customers during the month of August 2022, and also posted notice of the rate increase on its website. The notification included a comparison between current and proposed rates, and that the rates ultimately approved by this Commission will not exceed those identified in the notice. FCG also provided a direct notice to customers during May 2023, which identified the final, Commission-approved rates and charges. Our staff reviewed the direct notice and believe the notice reflects our approved rates and charges. We find that the approved rates and charges should become effective May 1, 2023. We further find the tariffs as provided in Attachment 6 are approved.

I. Approval of Tariffs Reflecting Approved Rates and Charges

1. Parties' Arguments

FCG did not provide an argument but took the position that we should approve tariffs reflecting our approved rates and charges and should direct our staff to verify that the revised tariffs are consistent with our decision.

2. Analysis and Conclusion

We have reviewed the cost of service study and associated tariffs which were revised to reflect our final approved revenue requirement in accordance with our vote from the March 28, 2023, Special Agenda Conference. The tariffs are approved and are hereby incorporated into this Order as Attachment 6.

X. Other Issues

A. Proposal For Addressing A Potential Change In Tax Law

1. Parties' Arguments

FCG argued that in light of the continuing debate surrounding tax law in the United States, there exists the possibility for a change in tax law either during or after the conclusion of the rate case that could have a material impact on the four-year proposal being presented by FCG. FCG would not be able to quantify the impacts until such time as a final bill is passed and signed into law. FCG's proposed tax adjustment mechanism would allow FCG to adjust base rates in the event tax laws change during or after the conclusion of this proceeding. FCG argued the proposed tax adjustment mechanism would ensure that the impact of future tax laws is promptly and appropriately reflected in base rates, whether that is an increase or decrease to tax expense. FCG argued this Commission has previously approved nearly identical tax adjustment mechanisms.

OPC argued that, by Order No. PSC-2017-0099-PCO-EI (2017 Gulf Tax Decision), we established a policy that a rate case is not the proper venue for establishing a prospective change in rates as a result of a future change in federal income tax rates. OPC also argued that as a matter of policy, we should decline to authorize the tax change provision because it is single issue ratemaking that would ignore the other relevant conditions that might exist at a time when tax laws might change in the future. FIPUG adopted the position of OPC.

OPC argued that for FCG to demand to receive a Commission-ordered tax adjustment mechanism on top of a fully litigated revenue requirement award violates prior Commission policy. OPC argued that since the company conceded that there is no impact of the August 2022 Inflation Reduction Act (IRA) on the company, it is undisputed that the purpose of the proposal is premature for some future, unknown (and purely speculative) tax law change.

2. Analysis

At issue is whether FCG's proposed tax adjustment mechanism (to adjust base rates in the event tax laws change during or after the conclusion of this proceeding) should be approved. The bulk of FCG's testimony relies on its FCG witness Campbell's testimony that FCG filed its rate case under the assumption that there was the potential for an increase in the Federal corporate tax rate either during the case itself or during the four year period when FCG's rate plan proposes no adjustments to base rates.

FCG has not accounted for or included any potential tax law changes in its current filing, and FCG witness Campbell agreed that in August 2022, a change in tax law was passed but did not have any immediate impact on FCG. Witness Campbell testified that FCG is still assessing the changes, but doesn't foresee anything affecting FCG. Further, witness Campbell admitted that he does not know of any new tax law changes that are pending or that the Company expects to be adopted in the near future.

3. Conclusion

We find that a tax law change provision in this case is unnecessary because there is no evidence supporting a need for it. Should there be a tax law that comes into effect that will affect the rates set forth in this order, a limited proceeding pursuant to Section 366.076, F.S., is available for FCG or OPC to address any potential future State or Federal income tax law changes, which would provide an opportunity to consider all of the issues arising from such tax law changes and to establish the appropriate rates at that time. As discussed above, we find that FCG's assurance to not initiate another rate proceeding before us over the next four years, or its "stay out" promise, is unenforceable. Accordingly, the tax law change provision is unnecessary. For this reasons, we hereby deny FCG's request for a tax law change provision.

B. SAFE Program Expansion for Mains and Services

At hearing, we approved a stipulation whereby all parties agreed that this Commission should approve the continuation and expansion of the SAFE program to include additional mains and services. The current SAFE program is set to expire in 2025 based on an original estimate of 254.3 miles of mains and services to be relocated from rear property easements to the street front over the ten-year program. FCG has subsequently identified approximately 150 miles of additional mains and services that are located in rear property easements and eligible for replacement under the SAFE program. As we have previously found, mains and services located in rear property easements present operational and safety concerns, including the age of the facilities, limitations on the Company's access to the facilities due to vegetation overgrowth, landscaping and construction in the easements, and potential gas theft or diversion and damages to the facilities. Therefore, continuation of the SAFE program beyond its 2025 expiration date and inclusion of an additional approximately 150 miles of mains and services is reasonable. FCG must propose a new investment/construction schedule and term for the SAFE program in its next applicable annual SAFE filing.

C. SAFE Program Expansion for "Orange Pipe"

At hearing, we approved a stipulation whereby all parties agreed that orange pipe is a specific plastic material that was used in the 1970s and 1980s that has been studied by the United States Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") and shown through industry research to exhibit premature failure in the form of cracking. The potentially compromised nature of the piping makes responding to leaks more hazardous since responders cannot safely squeeze the pipe without it cracking. In order to address this safety risk in a timely manner, FCG is seeking approval to expand the SAFE program cost recovery mechanism to include the capital investments necessary for the expedited replacement of approximately 160 miles of orange pipe installed before 1990. FCG must propose a new investment/construction schedule and term for the SAFE program in its next applicable annual SAFE filing.

D. Description of Adjustments

At hearing, we approved a stipulation whereby all parties agreed that FCG 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 the Commission's findings in this rate case.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that Florida City Gas' Petition for Rate Increase is granted in part and denied in part as set forth herein. It is further

ORDERED that each of the findings made in the body of this order is hereby approved in every respect. 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 the revised tariffs submitted by Florida City Gas, and the final rates and charges contained therein, as incorporated and attached to this Order, are hereby approved. It is further

ORDERED that the approved rates and charges for Florida City Gas shall be effective May 1, 2023. It is further

ORDERED that Florida City Gas shall file, within 90 days after the issuance of this order, a description of all entries or adjustments to its annual report, rate of return reports, and books and records, which will be required as a result of our findings in this rate case. It is further

ORDERED that after this final Order is issued this docket shall be closed.

By ORDER of the Public Service Commission this 9th day of June, 2023.

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.

TPS

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Any party adversely affected by the Commission's final action in this matter may request: 1) reconsideration of the decision by filing a motion for reconsideration with the Office of Commission Clerk, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or 2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water and/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 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.

COMPARATIVE AVERAGE RATE BASE

FLORIDA CITY GAS ATTACHMENT 1
DOCKET NO. 20220069-GU
PTY 12/31/23

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION	COMMISSION
	UTILITY PLANT					
	PLANT IN SERVICE	$659,463,015				
	Remove SAFE Assets		(49,408,313)			
	Remove Capital Lease Assets		(9,677,542)			
	SAFE Transfer to Base Rates		42,702,544			
	Total Plant-In-Service	$659,463,015	($16,383,311)	$643,079,704	$0	$643,079,704
	ACQUISITION ADJUSTMENT	$21,656,835				
	Total Acquisition Adjustment	$21,656,835	$0	$21,656,835	$0	$21,656,835
	CONSTRUCTION WORK IN PROGRESS	$30,868,480				
	Remove SAFE Assets		(3,555,214)			
	SAFE Transfer to Base Rates		879,174			
	Total Construction Work In Progress	$30,868,480	($2,676,040)	$28,192,440	$0	$28,192,440
	TOTAL UTILITY PLANT	$711,988,330	($19,059,351)	$692,928,979	$0	$692,928,979
	DEDUCTIONS					
	ACCUM. DEPR.- PLANT IN SERVICE	($224,359,876)				
	Remove SAFE Assets		2,709,929			
	Remove Capital Lease Assets		1,703,882			
	SAFE Transfer to Base Rates		(2,523,229)			
	2022 Depreciation Study		1,088,583			
	Total Accum. Depr.- Plant In Service	($224,359,876)	$2,979,165	($221,380,711)	$0	($221,380,711)
	TOTAL DEDUCTIONS	($224,359,876)	$2,979,165	($221,380,711)	$0	($221,380,711)
	NET UTILITY PLANT	$487,628,454	($16,080,186)	$471,548,268	$0	$471,548,268
	WORKING CAPITAL ALLOWANCE	$19,889,261				
	AEP Regulatory Asset		(1,132,457)			
	Clause Net Underrecoveries		(1,053,994)			
	Unamortized Rate Case Expense		(248,890)			
19	To Remove Unamortized Rate Case Expense				(1,742,227)	
22	Half of D&O Liability Insurance				(2,086)	
	Total Working Capital Allowance	19,889,261	(2,435,341)	17,453,920	(1,744,313)	15,709,607
	TOTAL RATE BASE	$507,517,715	($18,515,527)	$489,002,188	($1,744,313)	$487,257,875

Attachment 2

FLORIDA CITY GAS
Docket No. 20220069-GU
PTY 12/31/23
13 Month Average

ATTACHMENT 2

COMPANY POSITION	FCG PER BOOKS	SPECIFIC	PRO RATA	FCG ADJUSTED	RATIO	COST RATE	WEIGHTED COST
COMMON EQUITY	$262,522,369	$47,385	($5,541,003)	$257,028,751	52.56%	10.75%	5.65%
LONG TERM DEBT	165,323,588	(7,946,387)	(3,321,127)	154,056,074	31.50%	4.28%	1.35%
SHORT TERM DEBT	20,639,971	3,447	(435,638)	20,207,781	4.13%	1.78%	0.07%
CUSTOMER DEPOSITS	3,881,270	683	(81,921)	3,800,033	0.78%	2.64%	0.02%
DEFERRED TAXES	55,150,517	(78,791)	(1,162,177)	53,909,550	11.03%	0.00%	0.00%
TOTAL	$507,517,715	($7,973,663)	($10,541,866)	$489,002,189	100%		7.09%

STAFF POSITION	ADJUSTED PER BOOKS	SPECIFIC	PRO RATA	STAFF ADJUSTED	RATIO	COST RATE	WEIGHTED COST
COMMON EQUITY	$262,522,369	$47,385	($6,457,846)	$256,111,908	52.56%	9.50%	4.99%
LONG TERM DEBT	165,323,588	(7,946,386)	($3,870,658)	153,506,544	31.50%	4.28%	1.35%
SHORT TERM DEBT	20,639,971	3,447	($507,720)	20,135,698	4.13%	1.78%	0.07%
CUSTOMER DEPOSITS	3,881,270	683	($95,476)	3,786,477	0.78%	2.64%	0.02%
DEFERRED TAXES	55,150,517	(78,791)	($1,354,477)	53,717,249	11.02%	0.00%	0.00%
TOTAL	$507,517,715	($7,973,662)	($12,286,178)	$487,257,875	100%		6.44%

COMPARATIVE NET OPERATING INCOME

FLORIDA CITY GAS
DOCKET NO. 20220069-GU
PTY 12/31/23

ATTACHMENT 3
Page 1 of 2

ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
	OPERATING REVENUES					
	Operating Revenues	$116,217,009				
	Change in Unbilled Revenues	40,041				
	PGA		(34,053,742)			
	AEP Revenues		(726,069)			
	SAFE Revenues		(6,736,104)			
	Conservation		(6,997,154)			
	Franchise and Gross Receipts Tax Revenues		(3,158,626)			
3	LES Revenues				155,495	
35	Forecasted Misc. Revenues				(16,071)	
	TOTAL REVENUES	$116,257,139	($51,671,695)	$64,585,444	$139,424	$64,724,868
	OPERATING EXPENSES:					
	COST OF GAS	$34,075,912				
	Eliminate Fuel Expense		(34,075,912)			
	Total Cost of Gas	$34,075,912	($34,075,912)	$0	$0	$0
	OPERATION & MAINTENANCE EXPENSE	$32,720,885				
	Conservation		(6,901,558)			
	Rate Case Expense Amortization		497,779			
	Economic Development		(3,217)			
	Industry Dues Associated with Lobbying		(25,000)			
	Transfer of Support Costs to Clauses		(57,294)			
	Regulatory Commission Expenses/Fees		(250,628)			
11	Corrected AMI O&M Expense				(3,104)	
34	To Maintain Clause Support Costs in Base Rates				57,294	
38	Exclusion of Executive Incentive Compensation				(505,222)	
42	Remove Half of D&O Liability Insurance				(4,716)	
47	Updated Rate Case Expense				(27,570)	
	TOTAL O & M EXPENSE	$32,720,885	($6,739,918)	$25,980,967	($483,318)	$25,497,650
	DEPRECIATION & AMORTIZATION	$20,276,958				
	AEP Amortization		(679,200)			
	To remove SAFE assets		(1,273,253)			
	To transfer SAFE assets to base rates		1,189,568			
	2022 Depreciation Study		(2,197,500)			
	TOTAL DEPRECIATION & AMORTIZATION	$20,276,958	($2,960,385)	$17,316,573	$0	$17,316,573

COMPARATIVE NET OPERATING INCOME

FLORIDA CITY GAS
DOCKET NO. 20220069-GU
PTY 12/31/23

ATTACHMENT 3
Page 2 of 2

			COMPANY		STAFF	
ISSUE NO.		TOTAL PER BOOKS	COMPANY ADJS.	COMPANY ADJUSTED	COMMISSION ADJS.	COMMISSION ADJUSTED
	TAXES OTHER THAN INCOME	$9,740,548				
	To Remove SAFE Assets		(992,616)			
	To Transfer SAFE Assets into Base Rates		797,305			
	Franchise and Gross Receipts Expense		(3,158,626)			
52	LES Revenue RAF				777	
52	Forecasted Miscellaneous Revenue RAF				(80)	
52	Executive Incentive Compensation Payroll Taxes				(32,995)	
52	Updated Property Tax Estimate				(510,886)	
	TOTAL TAXES OTHER THAN INCOME	$9,740,548	($3,353,937)	$6,386,611	($543,184)	$5,843,427
	INCOME TAX EXPENSE					
	Income Taxes	$1,176,607				
	Income Taxes - Deferred	1,504,301				
	Taxes Corresponding to Adjustments		(1,151,104)			
	Interest Synchronization		38,247			
	2022 Depreciation Study		64,639			
53	Interest Synchronization				6,381	
53	Fallout Adj. Federal Income Taxes				231,378	
53	Fallout Adj. State Income Taxes				64,126	
	TOTAL INCOME TAXES	$2,680,908	($1,048,218)	$1,632,690	$301,884	$1,934,574
	TOTAL OPERATING EXPENSES	215,752,350	(48,178,370)	51,316,841	(724,617)	50,592,224
	NET OPERATING INCOME	($99,495,300)	($3,493,325)	$13,268,603	$864,041	$14,132,644

NET OPERATING INCOME MULTIPLIER

FLORIDA CITY GAS ATTACHMENT 4
DOCKET NO. 20220069-GU
PTY 12/31/23

DESCRIPTION	COMPANY PER FILING	STIPULATION
REVENUE REQUIREMENT	100.0000%	100.0000%
REGULATORY ASSESSMENT RATE	0.5000%	0.5000%
BAD DEBT RATE	0.4771%	0.4771%
NET BEFORE INCOME TAXES	99.0229%	99.0229%
STATE INCOME TAX RATE	5.5000%	5.5000%
STATE INCOME TAX	5.4463%	5.4463%
NET BEFORE FEDERAL INCOME TAXES	93.5766%	93.5766%
FEDERAL INCOME TAX RATE	21.0000%	21.0000%
FEDERAL INCOME TAX	19.6511%	19.6511%
REVENUE EXPANSION FACTOR	73.9255%	73.9255%
NET OPERATING INCOME MULTIPLIER	1.3527	1.3527

COMPARATIVE REVENUE DEFICIENCY CALCULATIONS

FLORIDA CITY GAS
ATTACHMENT 5
DOCKET NO. 20220069-GU
PTY 12/31/23

		COMPANY ADJUSTED		COMMISSION APPROVED
RATE BASE (AVERAGE)		$489,002,189		$487,257,875
RATE OF RETURN	X	7.09%	X	6.44%
REQUIRED NOI		$34,688,400		$31,363,264
ACHIEVED NOI		13,268,605		14,132,644
NET REVENUE DEFICIENCY		21,419,795		17,230,620
REVENUE EXPANSION FACTOR		1.3527		1.3527
REVENUE DEFICIENCY		28,974,822		23,308,073
LNG Revenue		(3,828,493)		(3,828,493)
Transfer of SAFE Investments		(5,696,211)		(5,330,459)
INCREMENTAL REVENUE INCREASE		$19,450,118		$14,149,121

RULES AND REGULATIONS (Continued)

3. GAS LEAKS

The Customer shall give immediate notice to the Company of leakage of gas. No deduction on account of leakage shall be required to be made from Customer's bills unless such leakage occurs as the result of fault or neglect of agents of the Company. In case of leakage or fire, the stopcock at the meter should be closed without delay and no light or flame used in the vicinity of the leak.

4. CONNECT CHARGE

A charge of $~~80.00~~ 90.00 for Residential service or $150.00 for Non-Residential service will be made on the Customer's next bill when gas service is initiated, connected or turned-on. If service is performed, at Customer request, outside of normal business hours the charges shall be $~~100.00~~110.00 for Residential service or $200.00 for Non-Residential service.

5. RECONNECTION CHARGE

A charge of $~~40.00~~ 90.00 for Residential service or $~~80.00~~ 105.00 for Non-Residential service will be made on the Customer's next bill when gas service is reconnected after disconnection for non- payment of bills. If service is performed, at Customer request, outside of normal business hours the charges shall be $~~50.00~~105.00 for Residential service or $~~100.00~~120.00 for Non-Residential service.

6. FAILED TRIP CHARGE

A charge of $20 for Residential and Non-Residential service will be made on the Customer's next bill when the Customer fails to keep a scheduled appointment with the Company's employee, agent or representative.

7. LATE PAYMENT CHARGE

A bill shall be considered past due upon the expiration of twenty (20) days from the date of mailing or other delivery thereof by 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 that the Late Payment Charge applied to the accounts of federal, state, and local governmental entities, agencies and instrumentalities shall be at a rate no greater than allowed, and in a manner permitted by applicable law.

8. RETURNED CHECKS

The service charge for each returned check shall be determined in accordance with section 68.065, Florida Statutes. Payment of the full amount of the dishonored payment, plus a service charge of $25 if the face value does not exceed $50, $30 if the face value exceeds $50 but does not exceed $300, $40 if the face value exceeds $300, or 5 percent of the face amount of the dishonored instrument, whichever is greater.

RESIDENTIAL SERVICE – 1 (RS-1)

APPLICABILITY

Service is available to Residential Customers using between 0 and 99 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubicfoot.

*MONTHLY RATE

Customer Charge	$~~12.00~~18.00
Distribution Charge, per therm	$~~0.46120~~0.67667
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

RESIDENTIAL SERVICE - 100 (RS-100)

APPLICABILITY

Service is available to Residential Customers using between 100 and 599 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubicfoot.

*MONTHLY RATE

Customer Charge	$~~15.00~~19.00
Distribution Charge, per therm	$~~0.40383~~0.57421
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

RESIDENTIAL SERVICE - 600 (RS-600)

APPLICABILITY

Service is available to Residential Customers using 600 or more therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge	$~~20.00~~25.00
Distribution Charge, per therm	$~~0.52690~~0.70799
Commodity Charge	Per Rider "A"

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 1 (GS-1)

APPLICABILITY

Service is available to Non-Residential Customers using between 0 and 5,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~25.00~~31.00	$~~25.00~~31.00
Distribution Charge, per therm	$~~0.37664~~0.57949	$~~0.37664~~0.57949
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 6K (GS-6K)

APPLICABILITY

Service is available to Non-Residential Customers using between 6,000 and 24,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~35.00~~44.00	$~~35.00~~44.00
Distribution Charge, per therm	$~~0.33960~~0.48722	$~~0.33960~~ 0.48722
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 25K (GS-25K)

APPLICABILITY

Service is available to Non-Residential Customers using between 25,000 and 119,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~150.00~~188.00	$~~150.00~~188.00
Distribution Charge, per therm	$~~0.32509~~0.44046	$~~0.32509~~0.44046
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

2. Each year the Company shall re-determine each Customer's eligibility based on their annual usage. If reclassification to another schedule is appropriate such reclassification shall be prospective only and shall not be retroactive.

GENERAL SERVICE - 120K (GS -120K)

APPLICABILITY

Service is available to Non-Residential Customers using between 120,000 and 1,249,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~300.00~~375.00	$~~300.00~~375.00
Demand Charge, per DCQ	$~~0.575~~0.719	$~~0.575~~0.719
Distribution Charge, per therm	$~~0.19379~~0.28336	$~~0.19379~~0.28336
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE - 1,250K (GS -1,250K)

APPLICABILITY

Service is available to Non-Residential Customers using between 1,250,000 and 10,999,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~500.00~~625.00	$~~500.00~~625.00
Demand Charge, per DCQ	$~~0.575~~0.719	$~~0.575~~0.719
Distribution Charge, per therm	$~~0.09361~~0.14073	$~~0.09361~~0.14073
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE – 11M (GS - 11M)

APPLICABILITY

Service is available to Non-Residential Customers using between 11,000,000 and 24,999,999 therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~1,000.00~~1,250.00	$~~1,000.00~~1,250.00
Demand Charge, per DCQ	$~~0.575~~0.719	$~~0.575~~0.719
Distribution Charge, per therm	$~~0.08000~~0.10320	$~~0.08000~~0.10320
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GENERAL SERVICE – 25M (GS - 25M)

APPLICABILITY

Service is available to Non-Residential Customers using 25,000,000 or more therms per year as determined by the Company.

CHARACTER OF SERVICE

A firm delivery service of gas, including RNG delivered into the Company's system by any customer, delivered by the Company or Customers' Third Party Supplier ("TPS") with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~2,000.00~~2,500.00	$~~2,000.00~~2,500.00
Demand Charge, per DCQ	$~~0.575~~0.719	$~~0.575~~0.719
Distribution Charge, per therm	$~~0.04000~~0.05160	$~~0.04000~~0.05160
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS. Only Non-Residential Customers are eligible to receive gas supply from a TPS.

DETERMINATION OF THE DEMAND CHARGE QUANTITY (DCQ)

The DCQ to be used in setting the Customer's Billing DCQ will be determined by the Customer's maximum daily requirements in terms of therm units per day based on readings taken from an Automatic Meter Reading (AMR) device installed at the premise. The DCQ used in setting the Billing DCQ shall be those from the Customer's daily metered therm consumption recorded for a period of up to three (3) years ending each March 31st. If historical consumption information of at least twelve (12) months is not available, then the Billing DCQ level shall be based upon the rating and expected usage of the Customer's gas equipment as determined by the Company.

The Billing DCQ will be determined annually by the Company based on the DCQ history, as determined above. The Customer's Billing DCQ shall be adjusted to reflect the maximum recorded DCQ. Adjustments will be made in April except the Company shall not increase such a Customer's Billing DCQ unless the Customer has had at least three (3) occurrences of DCQ's in excess of their current Billing DCQ.

GAS LIGHTING SERVICE (GL)

AVAILABILITY

See "Limitations of Service" below.

APPLICABILITY

Firm gas service for continuous street or outdoor lighting devices installed upstream of the Customer's meter.

LIMITATIONS OF SERVICE

This Rate Schedule is closed and is restricted to Customers who were served prior to March 17, 1975.

*MONTHLY RATE

Distribution Charge	$~~10.66~~10.69 per lamp
	($~~0.59237~~ 0.59363 per therm X 18 therms)

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. For the purpose of applying Riders or other billing adjustments usage of eighteen therms per lamp per month will be assumed.

MINIMUM BILL

The minimum monthly bill shall be the Monthly Rate.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

RESIDENTIAL STANDBY GENERATOR SERVICE (RSG)

APPLICABILITY

Service is available to Residential Customers whose only gas usage is for a standby electric generator.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubicfoot.

*MONTHLY RATE

Customer Charge:	$~~16.81~~25.00	
Distribution Charge:	0 - 14 therms	$0.00000 per therm
	More than 14 therms	$~~0.52248~~0.57421 per therm

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Subject to special condition 3 below, a customer receiving service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month term unless the customer terminates the service in writing within 30 days before the end of the term.

2. If the customer terminates the service before the 12-month term ends, the Customer will be billed the minimum bill for the remaining months of the service.

3. If the customer installs an additional gas appliance at the premise at which service is provided, then the customer will be transferred to the applicable rate schedule based on total therms.

4. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

COMMERCIAL STANDBY GENERATOR SERVICE (CSG)

APPLICABILITY

Service is available to Non-residential Customers whose only gas usage is for a standby electric generator with annual consumption of less than 120,000 therms.

CHARACTER OF SERVICE

A firm delivery service of gas delivered by the Company with a heating value on the order of 1,100 British Thermal Units per cubic foot.

*MONTHLY RATE

Customer Charge:	$~~24.00~~36.00	
Distribution Charge:	0 - 26 therms	$0.00000 per therm
	More than 26 therms	$~~0.49531~~ 0.57949 per therm

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A customer that receives gas supply from a TPS will be charged by the TPS for commodity according to any agreement between the Customer and the TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS OF SERVICE

1. Subject to special condition 3 below, a Customer receiving service under this schedule shall remain obligated to remain on this schedule for 12 months. This 12-month requirement shall be renewed at the end of each 12-month term unless the Customer terminates the service in writing within 30 days before the end of the term.

2. If the Customer terminates the service before the 12-month term ends, the Customer will be billed the minimum bill for the remaining months of the service.

3. If the Customer installs an additional gas appliance at the premise at which service is provided, then the Customer will be transferred to the applicable rate schedule based on total therms.

4. Application of this rate is subject to the general Rules and Regulations of the Company as they may be in effect from time to time and as filed with the regulatory authorities.

NATURAL GAS VEHICLE SERVICE-I (NGV-I)

(CLOSED SCHEDULE)

APPLICABILITY

For gas delivered to any Customer through a separate meter for the purpose of compression and delivery into motor vehicle fuel tanks or other transportation containers. NGV-I is only available to those Customers who are presently receiving this service as of August 13, 2013. Customers seeking such service after this date shall take service under the NGV-II terms of this Tariff.

*MONTHLY RATE

	Gas Supply from PGA	Gas Supply from TPS
Customer Charge	$~~25.00~~31.00	$~~25.00~~31.00
Distribution Charge, per therm	$0.23232	$0.23232
Commodity Charge	Per Rider "A"	Per TPS Agreement

*The charges set forth in this Rate Schedule will be adjusted for all other applicable Riders of this Tariff and any additional taxes, assessments or similar charges that are lawfully imposed by the Company. A Customer that receives gas supply from a TPS will be charged for commodity according to any agreement between the Customer and the TPS.

MINIMUM BILL

The minimum monthly bill shall be the Customer Charge. In addition, a minimum annual charge, if applicable, shall be assessed by applying the applicable rates and adjustments hereunder to the difference between the minimum therms, if any, established per the Customer's Agreement and the Customers annual usage.

TERMS OF PAYMENT

Bills are due upon receipt by the Customer and become delinquent if unpaid after expiration of twenty days from date of mailing or other delivery thereof by the Company.

SPECIAL CONDITIONS

Service under this Rate Schedule shall be subject to the general Rules and Regulations of the Company as they may be in effect from time to time, and as filed with the regulatory authorities.

SPECIAL CONDITIONS APPLICABLE TO CUSTOMERS RECEIVING GAS SUPPLY FROM THIRD PARTY SUPPLIERS (TPS)

1. See the Rules and Regulations for Transportation - Special Conditions for terms related to Customers taking Gas Supply from a TPS.

2. Automatic Meter Reading (AMR) equipment is required for transportation Customers served under this Rate Schedule using over 120,000 therms per year. See the Rules and Regulations for Metering for terms and conditions related to AMR's.

THIRD PARTY SUPPLIER
(TPS)
(Continued)

CREDITWORTHINESS (Continued)

In the event TPS fails to meet the terms of this Creditworthiness section, Company may, without waiving any rights or remedies it may have, and subject to any necessary authorizations, suspend TPS until such time as they are deemed compliant by the Company.

The insolvency of a TPS shall be evidenced by the filing by TPS, or any parent entity thereof, of a voluntary petition in bankruptcy or the entry of a decree or order by a court having jurisdiction adjudging the TPS, or any parent entity thereof, bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of the TPS, or any Parent entity thereof, under the Federal Bankruptcy Act or any other applicable federal or state law, or appointing a receiver, liquidator, assignee, trustee, sequestrator, (or similar official) of the TPS or any parent entity thereof or of any substantial part of its property, or the ordering of the winding-up or liquidation of its affairs.

MONTHLY RATE

Customer Charge	$400.00
Charge for each Transportation Customer served by the TPS	$~~6.07~~6.21

DETERMINATION OF THE AVERAGE DAILY DELIVERY QUANTITY ("ADDQ")

The ADDQ for each Customer without an AMR device will be calculated by the Company by dividing the Customer's usage for each of the most recent twelve (12) billing months by the total number of days in each billing month. Company may adjust Customer's ADDQ at any time, due to changes in Customer's equipment or pattern of usage. For new Customers, the initial ADDQ will be estimated by Company, based upon the rating of the Customer's gas equipment and expected utilization of the equipment. The TPS will be obligated to deliver the aggregate ADDQ each day for Customers it serves.

The Company will notify TPS of its aggregate ADDQ obligation for each day of the next succeeding month on the Company's EBB, or other means as determined by the Company. If TPS does not agree with Company's determination of TPS's aggregate ADDQ, it must notify the Company in writing within two business days no later than 5:00 p.m. Eastern Standard Time. Company and TPS will reconcile any differences no later than 5:00 p.m. Eastern Standard Time on the twentieth (20th) of the month.

Economic Development Gas Service (EDGS)
(Continued)

If the volume of gas purchased or transported in a contract year is less than the volume specified in the contract, the difference in the actual volume and the volume specified in the contract shall be deemed a volume deficiency. For any volume deficiency, the Customer shall be billed an amount equal to the non-gas volumetric charge that would have been billed for the delivery of the volume equal to the deficiency. The bill shall be computed in accordance with the applicable rate schedule that would otherwise apply subject to the discount provided under this rate schedule.

PAYMENT TERMS

All bills for service are due upon presentation. The stated net amount shown on the bill shall apply if payment is received on or before the date as specified on the bill. Payments received after that date shall be assessed late payment charges as defined in Section 7 on Sheet No. 13 of the Company's tariff.

BILLING ADJUSTMENTS

Bills for gas service hereunder shall be subject to adjustment for the applicable taxes, fees, and the cost of purchased gas in accordance with Purchased Gas Adjustment (PGA), and shall be subject to other adjustments, charges and/or credits as determined to be applicable to the applicable rate schedule under which the Customer would otherwise be served. The adjustment factor provided under this rate schedule will not be applied to the PGA and other adjustments factors.