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April 20, 2026

BY E-FILING

Mr. Adam Teitzman, Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: **Docket No. 20260026-GU – Application for Rate Increase by Florida City Gas.**

Dear Mr. Teitzman:

Attached, for electronic filing, on behalf of Florida City Gas, please find the Direct Testimony of John Taylor, as well as his Exhibits JT-1, JT-2, JT-3, JT-4, and JT-5.

Thank you for your assistance with this filing. As always, please don't hesitate to let me know if you have any questions whatsoever.

(Document 14 of 27)

Sincerely,

Beth Keating
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 20260026-GU: Petition for rate increase by Florida City Gas

Prepared Direct Testimony of John Taylor

Date of Filing: April 20, 2026

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I. INTRODUCTION

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

A. My name is John D. Taylor, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of Florida City Gas ("FCG" or the "Company"), a subsidiary of Chesapeake Utilities Corporation ("CUC").

Q. By whom are you employed and in what capacity?

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner.

Q. Please describe your educational background and professional experience.

A. My professional experience and educational background are presented in Document No 5 of my exhibit.

Q. What are the purposes of your prepared direct testimony in this proceeding?

A. The purpose of my direct testimony is to present and support FCG's proposed cost of service, revenue allocation, and rate design as part of the Company's request for base-rate relief in this proceeding. Specifically, my testimony supports (1) development of the billing determinants for the projected test year; (2) presents an embedded Class Cost of Service Study; (3) evaluates alternative cost-allocation and revenue-allocation methodologies; and (4) supports the Company's proposed rate structure changes and rate design. My testimony also sponsors and explains the relevant Minimum Filing Requirement ("MFR") schedules and supporting exhibits.

Q. Please provide a summary of the MFR schedules you are sponsoring.

A. A summary of the MFR schedules I am sponsoring is provided below.

- E-1: This schedule summarizes sales and revenue computed using present and proposed rates and projected billing determinants.

- E-2: This schedule provides the revenue calculation at present and proposed rates, summarizing data shown within the E-1 schedules.
- E-4: This schedule demonstrates monthly sales for the historical years of 2023, 2024, 2025, forecasted 2026, and the projected test year 2027. It also shows historical sales by rate schedule, coincident with each historical peak month.
- E-5: This schedule illustrates monthly bill comparisons under present and proposed rates by rate class.
- E-7: This schedule develops the average meter set and service cost by the current and proposed rate classes.
- E-8: This schedule is used for documenting the direct assignment of facilities.
- G-2 Pages 8-9: These schedules provide the calculation for revenue and cost of gas under the current and proposed rates for the projected test year 2027.
- H Schedules: These schedules reflect the Florida Public Service Commission's ("Commission") provided MFR template for the COSS displaying the cost for providing service to each rate class.

Q. In addition to the MFR Schedules you listed, are you sponsoring any exhibits as part of your direct testimony?

A. Yes. I am sponsoring the following, prepared by me or under my direct supervision. The documents are as follows:

- Exhibit JT - 1: List of MFR Schedules Sponsored or Co-Sponsored by John Taylor
- Exhibit JT - 2: Supplemental COSS - Demand-Based Classification of Distribution Mains (Schedules H-1, H-2, and H-3)
- Exhibit JT - 3: Allocation of Proposed Revenue Increase to Customer Classes

- Exhibit JT - 4: Development of Rates Under the Alternative Enterprise Resource Planning ("ERP") Revenue Requirement Recovery Approach
- Exhibit JT - 5: Curriculum Vitae of John Taylor

II. DEVELOPMENT OF BILLING DETERMINANTS AND ASSOCIATED REVENUES

Q. Which rate classes did you develop customer count forecasts and normal usage estimates for?

A. I developed customer count forecasts and normal usage estimates for Residential (RS-1, RS-100, RS-600) and General Service (GS-1, GS-6K, GS-25K) rate classes using regression methodology. The usage for these rate classes is considered to be temperature sensitive and therefore should be weather normalized (i.e., weather-normalized usage is an estimate of usage, if temperature, or more specifically Heating Degree Days[1] ("HDD"), is at historically normal levels).

Separate customer count forecasts and normal usage estimates are performed for the Southern geographic region surrounding Miami (the "Miami forecast region") and the region surrounding Melbourne (the "Melbourne forecast region"). This is done to more accurately account for the differing usage patterns and demand response to HDD across the two regions. The resulting regional customer forecasts and normal usage estimates are aggregated to the whole service territory.

For the other larger customer rate classes, actual numbers of customers and historical

[1] A Heating Degree Day ("HDD") is a measure of the number of degrees Fahrenheit by which the average daily temperature falls below a "base temperature" during a day. The base temperature often used is 65 degrees, but in modelling natural gas usage in Southern climates, a higher base is often used, reflecting the "need for heating" beginning at higher temperatures. In this analysis, a base of 75 or 85 degrees is used, as appropriate.

usage are used to project future customer numbers and usage. The Company performs this calculation drawing upon its expertise and insights regarding these large customers to provide a reliable projection of future usage.

Q. How are the projected test year revenues developed for each rate class?

A. Projected Test Year revenue is an estimate of the revenue based on forecasted billing determinants and the rates in place when filing for a rate change. It is developed by multiplying forecasted billing determinants for each rate class, comprised of total annual therms and bill counts (customer counts x 12) by the current rates. The billing determinants used to produce the Projected Test Year revenue are also used to estimate the revenue from proposed rates.

Q. Please describe the process used to develop normal usage estimates for Residential and General Service customers.

A. The process consists of two primary components:

1) Forecasting the number of customers by rate class, and
2) Estimating normal Usage Per Customer ("UPC") by rate class.

The normalized usage estimate results from the multiplication of the customer count forecast by the normalized UPC estimate (i.e., an estimate of UPC at normal HDD) for the Projected Test Year.

Q. What is the source of the customer count, Usage-per-Customer, and HDD data used in your analysis?

A. The Company provided historical billing data from January 2020 and customer count data, from which UPC was calculated. This data was aggregated to monthly usage and customer counts and allocated to Miami and Melbourne forecast regions.

Daily temperature data was acquired from NOAA for the Miami and Melbourne International Airports from which monthly HDD was calculated. A ten-year average of HDD was calculated to represent the ten-year Normal level of HDD by forecast region.

Q. How was the customer count forecast developed?

A. Customer number forecasts were developed for each rate class, for each forecast region. A fairly simple and straightforward methodology was employed. For rate classes in which there was a clear recent trend in customers numbers, a linear trend over the prior twelve months of actual customer numbers was extrapolated through 2027. For rate classes where there was not a clear trend, the last actual number of customers was used for the forecast for 2027.

Q. How was the estimate of normal UPC developed?

A. First, regression models are used to estimate the relationship between UPC and HDD for each rate class and forecast region. Then the models are evaluated at the estimate of normal HDD (i.e., the ten-year average of historical HDD) to develop an estimate of normal UPC, or an estimate of what UPC would be if HDD is at normal levels.

Q. Please provide an explanation of the UPC regression models.

A. Regression models are specified to estimate the relationship between UPC and a Constant, HDD terms, and a trend variable. In the regression, UPC is the "dependent" variable, and the Constant, HDD terms and trend variable are the "independent" or "explanatory" variables. The dependent variable is determined by, or "depends" on, the independent or explanatory variables in the model. Although evaluated individually for each rate class and forecast region, and as such may have different

specifications, the UPC regression models are generally of the standard form:

$$UPC_m = \textbf{Constant} + \beta_1 \times HDD_m + \beta_2 \times HDD_{m-1} + \beta_3 \times Trend$$

Where:

- UPC_m is Use-Per-Customer for the month 'm', e.g., January.
- HDD_m and HDD_{m-1} are HDD for the current month 'm', e.g., January, and the prior month 'm-1', e.g., December. Current and prior month HDD are used because UPC is based on usage billed in a month, which is comprised of actual usage during the current (billed) month and prior month.
- The **Constant** is the estimated constant coefficient (intercept) in the regression.
- β_1, β_2, β_3 are the estimated regression coefficients.

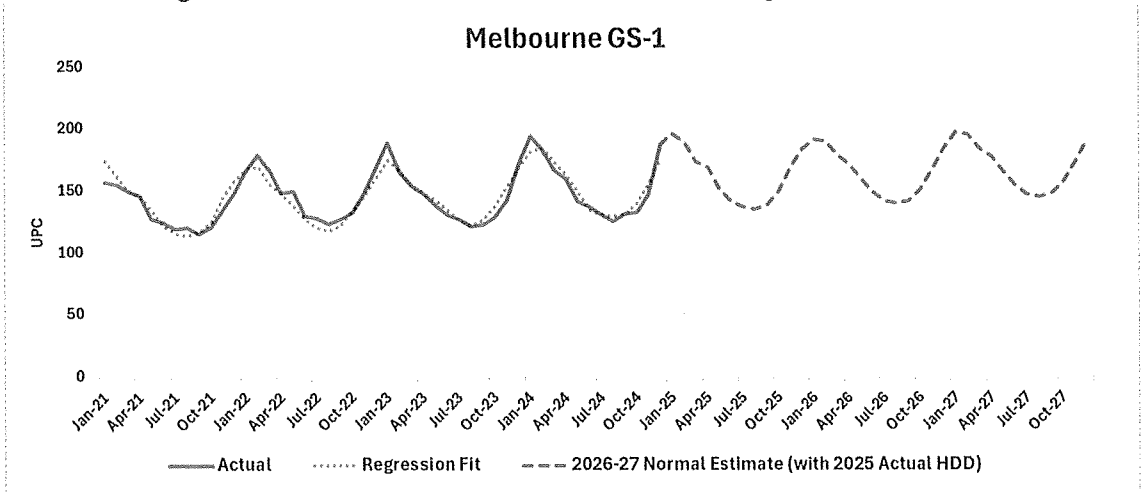
The estimated regression coefficients, for each rate class and region, along with the monthly normal HDD, are used to estimate, or "forecast," the normal monthly UPC; or in other words, estimate what UPC would be if HDD were normal.

Q. Please provide an example of the UPC regression analysis and normal UPC estimate.

A. Figure 1 graphically illustrates the UPC regression analysis and normal estimate for the General Service GS-1 rate class in the Melbourne forecast region. Actual Historical GS-1 UPC (solid blue line) is used to estimate the regression model. The regression fitted values (dotted red line) represent the UPC "explained" by the estimated

regression model, which is the basis for the estimate or "forecast" of normal UPC (dashed blue line).

Figure 1 – General Service GS-1 – Actual, Regression Fit, & Forecast



Q. How were these results used to develop the forecasted billing determinants?

A. The estimates of normal UPC developed from the regression analysis are multiplied by the customer forecasts to estimate normal usage for the Projected Test Year.

Q. Were the projections reviewed for reasonability by the Company?

A. Yes. After the projections were completed, they were reviewed by FCG personnel familiar with customer growth and usage trends in their service territory.

III. RATE SCHEDULE RESTRUCTURING

Q. Please discuss the Company's current customer base and rate structure.

A. The Company estimates that it serves approximately 130,000 customers at the end of the Test Year 2027. As shown in **Table 1**, the Company's customer portfolio primarily consists of its residential classes that together make up 93 percent of total customers. There are two types of commercial customers: (a) those taking service under the tariff rates, and (b) those taking service under negotiated rates. Currently,

there are six customers receiving services under the negotiated contract rates with average annual revenue totaling approximately $4.5 million.

Table 1 – Current Customer Structure

Line No.	Current Customer Class	Current Annual Applicability	Number of Bills	TY Number of Customers	Number of Customers % to Total	WN TY Sales (Therms)	WN TY Sales (Therms) % to Total	Total TY Base Revenue	Total TY Base Revenue % to Total
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RS-1	< 99	423,265	35,272	27.14%	2,404,557	1.89%	$ 9,245,859	10.66%
2	RS-100	100 - 599	1,001,965	83,497	64.25%	14,185,106	11.15%	27,182,566	31.33%
3	RS-600	> 600	24,046	2,004	1.54%	1,193,647	0.94%	1,446,248	1.67%
4	RSG	n/a	928	77	0.06%	1,827	0.00%	23,200	0.03%
5	GS-1	0 - 5,999	68,761	5,730	4.41%	13,309,708	10.47%	9,844,425	11.35%
6	GS-6K	> 6,000 < = 24,999	32,915	2,743	2.11%	28,125,575	22.12%	15,151,583	17.46%
7	GS-25K	> 25,000 < = 119,999	4,728	394	0.30%	14,641,038	11.51%	7,337,656	8.46%
8	GS-120K	> 120,000 < = 1,249,999	1,236	103	0.08%	35,834,584	28.18%	12,813,395	14.77%
9	GS-1,250K	> 1,250,000 < = 10,999,999	104	9	0.01%	17,457,355	13.73%	3,653,286	4.21%
10	GS-11M	> 11,000,000 < = 24,999,999	-	-	0.00%	-	0.00%	-	0.00%
11	GS-25M	>25,000,000	-	-	0.00%	-	0.00%	-	0.00%
12	CSG	<120,000	1,606	134	0.10%	19,691	0.02%	57,804	0.07%
13	**Total**		**1,559,553**	**129,963**	**100.00%**	**127,173,088**	**100.00%**	**86,756,023**	**100.00%**

Q. What changes are proposed to the current rate schedules?

A. The Company is proposing several modifications to its existing rate schedule and customer class structure to improve rate design, enhance administrative efficiency, and better align customer classes with usage characteristics. The proposed changes are summarized as follows:

Consolidation of Residential Classes – The existing residential rate schedules are consolidated to simplify the rate structure and improve consistency in how residential customers are served and billed.

Restructuring of Commercial Classes – The applicability thresholds for commercial rate schedules, including General Service -1 ("GS-1"), General Service – 6K ("GS-6K"), and General Service – 25K ("GS-25K"), are modified to further align customer class definitions with those used by CUC's other operating entities. This change promotes consistency and supports a more standardized and administratively efficient

rate structure.

Elimination of Gas Lighting Rate Schedule – The Gas Lighting rate schedule is proposed to be eliminated, as there are currently no customers taking service under this rate.

Elimination of Natural Gas Vehicle Service Rate Schedule – Similarly, the Natural Gas Vehicle Service rate schedule is proposed to be discontinued due to a lack of participating customers.

Q. What are the primary goals of modifying existing rate structure?

A. The primary objectives of modifying the existing rate structure are to establish rate classes that reflect price differences corresponding to variations in the cost to serve customers and to simplify and harmonize rate design across the different operating units of CUC.

The proposed structure introduces revised applicability thresholds based on customer consumption levels, allowing customers with similar usage characteristics to be grouped more consistently and supporting alignment with cost-of-service. These modifications reduce unnecessary segmentation across residential customers, improve transparency, and enhance administrative efficiency by creating a more uniform and cohesive rate framework across operating units.

At the same time, it is important to recognize that broader rate design objectives—such as full standardization of rate schedules and comprehensive tariff consolidation across operating entities—cannot be achieved within a single rate case proceeding. Accordingly, the Company is implementing these changes on a gradual, step-by-step basis to ensure continuity, manage customer impacts, and allow for a measured

transition toward a more fully aligned and standardized rate structure over time.

A. RESIDENTIAL RATE CLASS CONSOLIDATION

Q. Please summarize the proposed residential rate schedule structure.

A. The Company proposes to consolidate its existing Residential Service Classes (RS-1, RS-100, and RS-600) into a single residential rate class.

Q. Why does the company propose to consolidate residential classes?

A. The Company's primary objective in consolidating residential rate schedules is to align customers more closely with the cost to serve and to reduce intra-class subsidization. By combining the existing classes into a single residential class, the Company can more appropriately reflect the largely uniform cost of providing service to residential customers.

Q. Why is there a need to consolidate the existing three residential schedules?

A. The need to consolidate the existing residential rate schedules is driven by ongoing trends in customer usage and cost recovery. The Company has observed a consistent decline in average UPC, which reduces revenue derived from volumetric charges. As consumption declines, the ability to recover costs through usage-based rates is diminished.

At the same time, the existing residential classes have relatively low customer charges, resulting in under-recovery of fixed costs associated with serving these customers. This issue is further compounded by growth in the number of customers within the smaller residential classes, increasing the overall shortfall in cost recovery. Additionally, the current multi-tiered structure can result in customers moving between rate classes due to relatively minor changes in annual consumption. These

movements do not reflect meaningful differences in the cost to serve but can lead to variability in customer classification and bill outcomes.

The Company expects these trends—declining usage and misalignment in cost recovery—to continue. Without structural changes, these conditions would result in ongoing revenue imbalances across residential customers.

By consolidating the existing schedules into a single class and re-evaluating cost responsibility, the Company can better align its rate design with the underlying cost of providing service and establish a more sustainable and stable revenue framework.

Q. Are there other considerations relating to the movement towards consolidating the residential rate classes?

A. Yes. The consolidation is also supported by the fact that the cost of providing gas service to residential customers is largely independent of individual consumption levels. The primary costs—such as infrastructure, meters, system maintenance, and customer service—are predominantly fixed and do not vary significantly with usage.

In addition, core service functions such as meter reading, billing, and customer support are performed similarly for all residential customers regardless of their consumption levels. As a result, maintaining multiple rate classes based solely on usage does not meaningfully reflect differences in the cost to serve.

Consolidating residential classes therefore promotes a more equitable allocation of costs by aligning rates with the underlying service characteristics and reducing disparities that are not supported by cost differences.

B. COMMERCIAL RATE CLASS RESTRUCTURING

Q. Please summarize the proposed commercial rate schedule structure.

A. The Company's proposed rate schedule modifications are limited to certain existing commercial rate schedules, specifically General Service -1 ("GS-1"), General Service – 6K ("GS-6K"), and General Service – 25K ("GS-25K"), while all other rate schedules remain unchanged. As shown in **Table 2** below, the proposed changes involve adjustments to the applicability thresholds for these rate classes. These revisions are intended to better align customer groupings based on annual consumption and to support a more consistent and streamlined class structure across the Company's various operations.

Table 2 – Proposed Commercial Class Rate Schedules

Line No.	Current Customer Class	Current Applicability	Proposed Customer Class	Proposed Applicability	Number of Customers	WN TY Sales (Therms)
	(1)	(2)	(3)	(4)	(5)	(6)
1	GS-1	0 - 5,999	GS - 1	0 - 9,999	5,730	13,309,708
2	GS-6K	6,000 - 24,999	GS - 1	<= 9,999	1,413	10,016,907
3			GS - 2 (10K)	>= 10,000 <= 49,999	1,329	18,108,669
4	GS-25K	25,000 - 119,999	GS - 2 (10K)	>= 10,000 <= 49,999	291	8,283,768
5			GS - 3 (50K)	>= 50,000 <= 119,999	103	6,357,270

Q. What analyses were utilized in developing the proposed commercial rate classes?

A. The Company evaluated historical customer consumption data for calendar years 2022 through 2025 to assess the distribution of annual usage and to identify appropriate applicability thresholds for commercial rate classes for CUC's two local distribution operating entities in Florida: FCG and Florida Public Utility Company ("FPUC"). This evaluation was focused on commercial classes with consumptions levels less than 120,000 per year and included reviewing customer frequency distributions, consumption patterns, and the relative density of customers across usage ranges.

The analysis demonstrated that customers consuming 10,000 therms or less annually form a continuous and densely populated segment. There were no distinct clustering patterns, variable points, or breaks in the distribution at lower thresholds that would indicate meaningful separation between customer groups. In practical terms, customer counts declined gradually as usage increased, rather than exhibiting step changes that would support additional segmentation.

Because of this continuous distribution, introducing additional breakpoints below 10,000 therms would not meaningfully distinguish customers based on consumption characteristics. Instead, such segmentation could introduce unnecessary complexity, increased administrative burdens, and greater potential for customers to move between classes due to normal year-to-year variability in usage.

The analysis further identified a logical intermediate grouping of customers with annual consumption between 10,000 and 50,000 therms. Customers within this range represent a transition between smaller, lower-volume commercial accounts and larger, higher-volume users. Establishing the GS-2 (10K) rate class for this range provides a structured progression in applicability thresholds and improves consistency in how customers are grouped as usage increases.

The 50,000 therm threshold was selected as the upper bound of this intermediate class to create a clear and practical transition point to higher-volume customers. Customers above this level generally exhibit larger and more consistent consumption patterns, making them more suitable for potential future rate design considerations such as demand-based components. Establishing this breakpoint provides a forward-looking framework while maintaining a clear and logical class structure.

Q. How does the proposed commercial rate class structure compare to CUC's other operating utilities?

A. The proposed commercial rate class structure is not fully aligned with the current structure used by the CUC's other operating utilities. However, in developing the proposed applicability thresholds, CUC evaluated customer usage data across both FCG and FPUC to move toward greater consistency in rate class design.

The proposed structure represents a step toward harmonizing rate schedules across CUC's operating units by establishing more comparable applicability ranges based on consumption. The CUC anticipates that further alignment may be addressed in future proceedings involving its other utilities.

Q. Does the proposed rate structure align with industry principles?

A. Yes. The proposed approach is consistent with industry literature on developing sound rate structures[2]. In addition, the NARUC Gas Distribution Rate Design Manual notes,

> In order to design rates, it is first necessary to divide the utility's customers into various rate classes. This is done by defining rate classes according to certain characteristics which are common to all members of the class. The specific factors used to define rate classes will depend upon the characteristics of the customer population and the goals to be achieved. Factors which have been used to define rate classes include: (1) size, (2) customer type, (3) type of usage, (4) interruptible or firm service, (5) load factor, and (6) alternate fuel capability. In determining which factors to use in setting rate classes, it is necessary to consider the objectives to be achieved. In theory, utility rates could be designed for only a single rate

[2] See Bonbright, James, Danielsen, Albert, and Kamerschen, David. "Principles of Public Utility Rates." Public Utilities Reports, Inc. 1988. Second edition, at 377-407.

class. However, an appropriate division of customers into rate classes can achieve a variety of goals, including economic efficiency, fairness and equity, reflection of costs, social needs, competitiveness, operating efficiency, business climate development, rate stability, conservation and political feasibility. The need for a reasonable division of rate classes to achieve these goals exists whether the rates are designed based on cost of service principles or some other means.[3]

IV. EMBEDDED CLASS COST OF SERVICE STUDY

Q. What is the general purpose and use of a COSS in regulatory proceedings?

A. The purpose of a COSS is to allocate the local distribution company's ("LDC's") overall adjusted test year costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. The requirement to develop a COSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, a COSS provides insights into the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class, help determine the individual class revenue

[3] National Association of Regulatory Utility Commissioners, Staff Subcommittee on Gas, "Gas Distribution Rate Design Manual."," (June 1989) at 15-17.

responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the COSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. Are there factors that influence a gas utility's overall cost allocation framework when performing a COSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation to allocate costs to customer groups. Cost causation addresses the question of which customer or group of customers causes the utility to incur particular costs. To make this determination, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors which can influence the cost allocation methods used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility. It is important to understand these considerations because they influence the overall context of a utility's cost of service study and indicate where efforts should be focused to conduct a more detailed analysis of the utility's gas system.

Q. Are cost of service studies an application of economic theory to cost allocation?

A. The allocation of costs using a COSS is not a theoretical economic exercise. Rather, it is a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general matter, utilities must be allowed a reasonable opportunity to earn a return on the assets used to serve

their customers and recover their operating expenses. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the cost information in the COSS to understand and quantify the allocated costs in each customer class is a useful step in the rate design process to guide the development of rates.

Q. What principles are used in the allocation of common costs?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs. To answer this question, it is necessary to establish a link between a LDC's customers, and the particular costs incurred by the utility in serving those customers. An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. For example, providing a customer with gas service during peak periods can have much different cost implications for the utility than service to a customer who requires off peak gas service.

Q. Why are the relationships between customer requirements, load profiles, and usage characteristics significant to cost causation?

A. The company's distribution system is designed to meet three primary objectives: (1) to

extend distribution services to all customers entitled to be attached to the system; (2) to meet the aggregate design day peak capacity requirements of all customers entitled to service on the peak day; and (3) to deliver volumes of natural gas to those customers either on a sales or transportation basis. There are certain costs associated with each of these objectives. Also, there is generally a direct link between the manner in which such costs are defined and their subsequent allocation.

Customer-related costs are incurred to attach a customer to the distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served and continue to be incurred whether or not the customer uses any gas. They generally include capital costs associated with minimum size distribution mains, services, meters, regulators and customer service and accounting expenses.

Demand - or capacity-related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity-related component of cost relative to the company's requirements for serving their customers.

Commodity-related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity-related to the extent they vary with the amount of gas volumes purchased by the company for its sales service customers.

Where costs are incurred for a customer or class of customers and can be so identified,

direct assignment of costs can be utilized. Where costs cannot be directly assigned, the development of allocation factors by customer class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service.

V. FCG'S COSS

A. PROCESS STEPS AND STRUCTURE OF THE COSS

Q. Please describe the process of performing FCG's COSS analysis.

A. In this case, two COSS were developed for comparative purposes: (1) Proposed COSS - Customer/Demand Classification of Distribution Mains and (2) the Supplemental COSS - Demand-Based Classification of Distribution Mains. The Supplemental COSS was conducted in accordance with methods widely adopted in this jurisdiction and is presented in Exhibit JT-2. The Proposed COSS reflects the Company's proposed classification and allocation of mains investments, which I will discuss later in my direct testimony.

Q. Please describe the cost of service model utilized to develop the COSS.

A. The Company used the Commission's required Excel-based cost of service model within the MFR H Schedules. The required cost of service model within the MFR H Schedules consists of several pages used to allocate various components of the company's revenue requirements. The MFR H-1 Schedule summarizes the results of these allocations, showing the current rate of return for each rate class and the revenue

requirement at the proposed rate of return.

Q. What was the source of the cost data analyzed in the COSS?

A. All cost of service data was extracted from the Company's total revenue requirement and schedules in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. Please describe the organization of the COSS.

A. The COSS starts with the population of MFR Schedule H-3. Within MFR Schedule H-3, all projected expenses (operating, maintenance, depreciation, amortization, income taxes, and taxes other than income taxes), rate base, and accumulated depreciation are listed by the Federal Energy Regulatory Commission general ledger and plant account classifier. MFR Schedule H-3 classifies costs as Customer, Capacity, and Commodity. Then, MFR Schedule H-2 allocates these classified costs to each rate class included in the COSS. MFR Schedule H-1 summarizes these allocations, illustrating the deficiency for each rate class and the current rate of return.

Q. Please describe the content of MFR Schedule H-1, which summarizes the results of the COSS.

A. The difference between the computed revenue requirement and the revenue that would be derived without making any rate changes equals the Company's Operating Income deficiency, MFR Schedule H-1 Schedule D. The rate of return is determined by subtracting the revenue derived from each rate class from the expenses attributable to each rate class and then dividing the result by the rate base attributed to each rate class.

MFR Schedule H-1, Schedule C, included within the Commission-provided MFR H Schedule, consists of two pages. The first page presents the rate of return projected to be realized by each rate class under present rates for the projected test year. The second page reflects the resulting rate of return by rate class under proposed revenues, thereby establishing the Company's proposed revenue targets by class, as further discussed in Section VII below. Lastly, MFR Schedule H-1 Schedule A contains the Company's proposed revenue targets by rate class, customer charge rates, and volumetric rates.

Q. How are the rate classes structured for purposes of conducting the cost of service model?

A. The rate classes in the COSS are structured based on the proposed customer class framework, grouping customers according to similar characteristics, usage patterns, and contributions to system demand. This approach reflects similarities in cost causation and service requirements, supporting an equitable allocation of costs based on each class's use of the Company's system.

Q. How are Special Contract customer revenues and costs treated in the COSS?

A. In the COSS, revenues generated from Special Contract customers are credited to all customer classes based on the allocation of total revenue requirements. At the same time, when developing allocation factors, the costs and usage characteristics associated with Special Contract customers are excluded. For example, their design day demand and usage is not included in the development of Peak and Average ("P&A") allocation factors. As a result of this approach, all customer classes receive a proportionate share of both the costs and revenues associated with Special Contract customers. Consequently, in the presentation of the COSS results and MFRs, no costs are directly

assigned to the Special Contract customer class.

Q. Does the COSS include gas commodity costs?

A. No. All commodity-related costs and revenues were excluded from the Company's provided test year revenue requirements and COSS.

Q. Were direct assignments of plant made in the COSS?

A. Yes. A special study was performed to directly assign a portion of distribution plant installed to serve specific customers within GS-5 (1,250K) class. The costs related to these facilities from the various plant accounts were directly assigned to this class as shown on MFR Schedule H-3 supported by Schedule E-8.

B. DEVELOPMENT OF WEIGHTED CUSTOMER ALLOCATOR

Q. Please discuss the development of the Weighted Customer Allocator.

A. The Meter-Regulators and Services studies are used to calculate the "Weighted Customer Allocator" that is being used to allocate some customer–related costs in the COSS. The weighted customer-related allocation factor is derived based on the results of Meter-Regulators and Services studies. It's a composite allocation factor that incorporates the unit costs for meters, regulators, and services into one factor and is applied to account balances to allocate costs to the customer classes.

Q. Please discuss the development of the Meter and Regulator study.

A. The study was developed using the quantities and types of meters installed per premise or rate schedule as the primary basis for analysis. However, historical cost data at the premise or rate schedule level was not available at that level. Since historical cost information was unavailable, the study instead utilized the estimated replacement cost

of each meter type. The average meter and regulator replacement costs were then linked to the meter records dataset, which includes a comprehensive count of all meter types associated with each rate schedule.

Using this data, the study determined the total replacement cost for each customer class. The relative unit cost for each customer class was then developed. This process allowed for an accurate allocation of costs and ensured that each customer class was assigned an appropriate share of the total cost of meters and regulators.

Q. Please discuss the development of the Service Study.

A. The Service Study was developed by allocating investment in service lines to customer classes based on the number of customers, with weighting factors applied to account for relative differences in unit investment cost and service line length. The investment incurred to connect customers is determined by the average service line length and the unit cost per foot of service line.

To ensure accuracy, service lines were categorized into three groups based on diameter: (1) small services, which included diameters of up to one inch; (2) medium services, which included diameters between one and two inches; (3) large services, which included service lines with diameters over two inches. The original cost data for service lines was indexed to current dollars using the Handy-Whitman Index for the South Atlantic Region. This adjustment ensured that all costs reflected replacement cost values rather than historical costs.

Customers were then grouped based on meter size into small meters, medium meters, and industrial meters. Service unit costs were applied to the number of customers in each group to calculate the total estimated service costs by customer class and the

corresponding cost per customer. The relative weighting factor was then calculated using the Residential Class as a baseline. This factor was then multiplied by the test year customer count for each customer class to derive the final allocation factors.

C. CLASSIFICATION AND ALLOCATION OF DISTRIBUTION MAINS

Q. How did the Company's COSS classify and allocate investment in distribution mains?

A. As discussed above, the Company conducted two sets of COSS analyses to evaluate the classification and allocation of distribution mains investment. Consistent with past filings, the Company presented a study using the Demand-Based Classification of Distribution Mains methodology for informational purposes as shown on Document No. 2 of my exhibit. However, the Company is proposing a shift toward a Customer/Demand classification and allocation methodology to refine cost allocation to better match cost causation, which I will explain a little later in my testimony.

Given that this represents a change in methodology, the Company proposes a phased implementation. Specifically, the Customer/Demand approach is applied only to small diameter mains, while larger diameter mains continue to be classified and allocated under the Peak and Average method.

For purposes of the mains classification analysis, the Company categorizes distribution mains with diameters of 2 inches and less as small mains. The study indicates that approximately 50 percent of total mains investment is associated with these small-diameter facilities.

Under the proposed Customer/Demand COSS, small diameter mains are classified as 60 percent customer-related and 40 percent demand-related. Since small mains

represent approximately 50 percent of total mains investment, this results in approximately 30 percent of total mains being classified as customer-related (i.e., 60% applied to 50%). The customer-related portion is allocated based on the number of customers, while the demand-related portion is allocated based on Peak and Average factor.

This approach allows the Company to improve cost alignment for a significant portion of distribution mains investment while maintaining continuity with established methods for the remainder of the system.

Q. Were there any other differences in methodology between the Supplemental COSS - Demand-Based Classification of Distribution Mains and Proposed COSS - Customer/Demand Classification of Distribution Mains?

A. No. The primary distinction between the Supplemental COSS and the Proposed COSS is the treatment of distribution mains. In the Supplemental COSS, distribution mains are classified entirely as demand-related, whereas in the Proposed COSS, distribution mains are classified using a Customer/Demand approach.

All other aspects of the methodology remain consistent between the two studies. This includes the classification of other plant and expense components, the allocation factors applied, and the overall cost-of-service framework. As a result, any differences in the study results are attributable solely to the change in how distribution mains are classified and allocated.

Q. Please discuss the primary difference between the two methods.

A. The primary difference between the two methods is how distribution mains are classified and allocated among customer classes.

Under the Customer/Demand classification, distribution mains are divided between customer-related and demand-related components. A portion of the costs is allocated on a per-customer basis to reflect the investment required to connect and serve customers, while the remaining portion is allocated based on demand or usage. This approach assigns a greater share of costs to classes with a higher number of customers, such as residential classes, and reduces the reliance on commodity-based allocation.

Under the Demand-Based classification, distribution mains are treated entirely as demand-related plant and are allocated using demand and commodity based allocator (Peak and Average Method). The use of a commodity-based allocation factor assigns more cost to higher load factor customers and less cost to lower load factor customers. On most gas distribution systems, this results in a shift of costs away from residential customers and toward industrial or large volume customers.

The rationale for using a commodity-based allocation factor, usually discussed by cost analysts supporting such a method, is that the gas distribution system would not be built if it were not for customers' commodity consumption throughout the year. Their argument relies upon the "annual gas delivery function" concept; a notion that a gas distribution utility delivers a gas commodity through its distribution system throughout the year. These cost analysts view the "annual gas delivery function" as the reason for the existence of gas distribution utilities, and it is the reason why those facilities were originally installed. They then conclude that the allocation of costs using cost causation principles should match the use of the system across the year regardless of how that usage relates to specific investments. While it is obvious that all customers utilize the utility's gas distribution system to receive delivery service

throughout the year, that fact provides little to no insight into the manner in which the utility actually incurs costs to provide such service. In reality, there are two cost factors that influence the level of distribution mains installed by an LDC. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on LDC's gas system by its customers. Second, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by LDC.

Q. Is annual throughput a reasonable basis for assigning costs to a gas utility's customers?

A. No. In my opinion, there is no cost causative basis for using annual throughput to allocate the costs of a gas utility, such as FCG, to its classes of service. It is easy to demonstrate from a number of different considerations that throughput does not cause distribution main costs. First, there is the regulatory test: whenever costs are related to throughput, regulators recognize that the level of those costs must be adjusted for the test year in the rate case to normalize the costs for weather. If distribution main costs were a function of throughput, there would be a weather normalization adjustment required to determine the test year level of costs to be included in the utility's rates. There is no regulatory body that adjusts the cost of distribution mains for normal weather because no one can demonstrate that mains cost varies with throughput. Second, there is a logical argument that no distribution main costs are caused by

throughput. Once this amount of capacity is installed, the costs are fixed and do not change for any amount of gas flowing through the utility's gas system on any other days. So long as the design day requirements of the system do not change and no new customers are added to the system, the cost for mains will not change regardless of the annual changes in throughput that result from weather and conservation. A simple example will illustrate this fundamental principle. Consider two customers that impose the same design day demand on the gas utility's distribution system but have different annual load factors. To serve the identical demand or capacity requirements of these customers, the gas utility must provide sufficient distribution main capacity for each based on the design characteristics of their loads. Therefore, the demand-related costs are the same to serve these two customers because their design day demands are the same. However, each customer would be allocated a different level of costs if an annual throughput allocation factor was used. This occurs because the customer with the higher load factor (and higher annual usage) would receive a greater share of costs relative to the customer with the lower load factor (and lower annual usage). In effect, the customer with a high load factor, who is using the company's gas system most efficiently, is penalized for its efficiency.

Q. Is the method used by the company to determine a customer cost component of distribution mains a generally accepted technique for determining customer costs?

A. Yes. Two of the more commonly accepted literary references relied upon when preparing embedded cost of service studies, Electric Utility Cost Allocation Manual, by John J. Doran et al, National Association of Regulatory Utility Commissioners

("NARUC")[4], and Gas Rate Fundamentals, American Gas Association, both describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. The use of a customer component for distribution facilities, particularly distribution mains, is a widely accepted approach in the gas industry.

The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and (2) the most commonly installed, minimum-sized unit of plant investment.

Under the zero-intercept approach, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero-inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the LDC's gas system against the size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. That is, the method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system.

[4] National Association of Regulatory Utility Commissioners. (January 1992). Electric Utility Cost Allocation Manual. Washington, D.C. Available for download at: https://pubs.naruc.org/pub/53A3986F-2354-D714-51BD-23412BCFEDFD

For purposes of determining the customer component of distribution mains to be used in FCG's COSS, the zero-intercept method was utilized.

Q. Would one expect there to be a strong correlation between the number of customers served by FCG and the cost of its system of distribution mains?

A. Yes. Development of the Company's distribution system over time is a dynamic process. Customers are added to the distribution system on a continuous basis under a variety of installation conditions. Accordingly, this process cannot be viewed as a static situation where a particular customer being added to the system at any one point in time can serve as a representative example for all customers. Rather, it is more appropriate to understand and appreciate that for every situation where a customer can be added with little or no additional footage of mains installed, there are contrasting situations where a customer can be added only by extending the distribution mains to the customer's "off-system" location.

Recognizing that the goal is to more reasonably classify and allocate the total cost of FCG distribution mains facilities, it is appropriate to analyze the cost causation factors that relate to these facilities based on the total number of customers serviced from such facilities. Accordingly, the concept of using a zero- intercept approach for classifying distribution mains simply reflects the fact that the average customer serviced by the Company requires a minimum amount of mains investment to receive such service. Thus, it is entirely appropriate to conclude that the number of customers served by FCG represents a primary causal factor in determining the amount of distribution mains cost that should be assessed to any particular group of customers. One can readily conclude that a customer component of distribution mains is a distinct and

separate cost category that has much support from an engineering and operating standpoint.

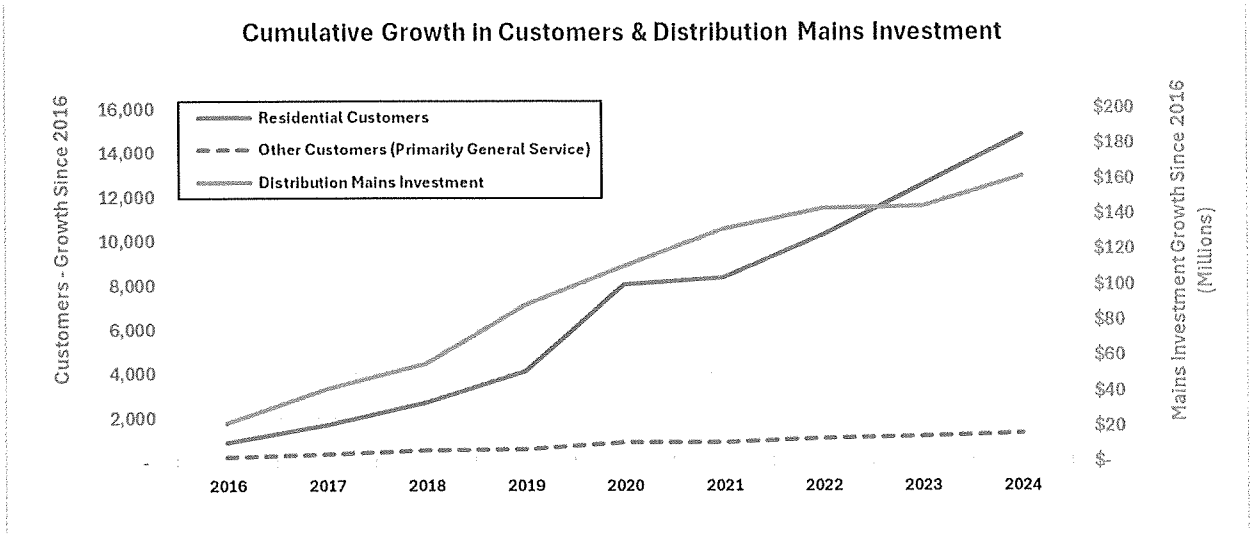
Q. Have you analyzed the relationship between the number of customers served by FCG and its level of investment in distribution mains?

A. Yes. I analyzed both customer growth and the investment in distribution mains. The results of the analysis are presented in Table 1 below. The graph illustrates the relationship between customer growth and distribution mains investment over the 12-year period from 2015 to 2024. The two primary customer segments — Residential Customers and Other Customers (Primarily General Service), show a steady increase in investment and customer count, with residential customers experiencing the most significant growth. It is important to note that the correlation coefficient between mains investment and customer growth is 0.96.

The Total Distribution Mains investment closely follows the trend of customer growth, indicating that infrastructure expansion has been aligned with rising customer base . This suggests that as more customers were added, there was a proportional increase in investment to support the necessary distribution infrastructure.

This data underscores a strong correlation between customer growth—primarily in the residential sector—and the ongoing investment in distribution mains, ensuring reliability and capacity for future expansion.

Figure 2 - Customer Growth and Distribution Mains Investments



Q. How does this analysis support the Company's proposal to introduce customer components in the classification of the distribution mains?

A. The analysis highlights a strong correlation between customer growth and investment in distribution mains, demonstrating that as the number of customers increases, so too does the total investment in infrastructure. This relationship highlights how customer expansion drives mains investment rather than being driven solely by peak demand or annual usage. This relationship highlights how customer expansion drives mains investment rather than being driven solely by peak demand or annual usage.

Among all customer segments, residential customers exhibit the most significant growth, aligning closely with increases in distribution mains investment. This trend suggests that a substantial portion of mains investment relates to connecting customers rather than merely accommodating higher consumption levels. The infrastructure expansion, therefore, is not just a response to increased gas usage, but a direct function of growing customer numbers, making a compelling case for introducing a customer

component in cost allocation. This classification ensures a fairer distribution of costs, particularly for small-diameter mains, which are predominantly installed to serve new residential customers.

D. ALLOCATION OF OTHER RATE BASE ITEMS

Q. Can you discuss the allocation of other rate case accounts?

A. Yes. The allocation of other rate case accounts in the COSS is based on a combination of customer-, demand-, and plant-related allocators, selected to reflect the underlying cost drivers associated with each category of investment. The application of these allocators is presented in Schedule H-2.

Customer-related accounts—such as services, meters, and house regulators—are allocated based on the results of the relevant studies discussed above. Other customer-related costs are allocated using customer counts or weighted customer measures, reflecting that these costs are incurred to connect and serve individual customers, largely independent of usage levels.

Capacity (Demand)-related accounts are allocated using peak and average demand allocators. These allocators reflect each class's contribution to system peak requirements as well as throughput, consistent with methodologies widely adopted in this jurisdiction and established precedent.

Plant-related and shared system accounts—such as general plant, intangible plant, and working capital—are allocated using composite allocators that incorporate both customer and demand components. These allocators are intended to approximate overall system utilization and ensure that shared costs are distributed proportionally across customer classes.

E. OPERATION & MAINTENANCE, CUSTOMER ACCOUNTS & SERVICES, AND ADMINISTRATIVE & GENERAL EXPENSES

Q. How were operations and maintenance ("O&M") expenses classified and allocated in the COSS?

A. Generally, the classification and allocation of the O&M expenses followed the treatment of the related plant accounts. For example, the treatment of FERC Account 879 (Customer Installations Expense), was allocated using the weighted customer allocation factor. Similarly, FERC Account 874 (Mains and Services Expenses) was allocated based on the allocation methodology applied to the Plant accounts for Mains and Services. This approach ensures that O&M expenses are assigned in a manner consistent with cost causation principles and the underlying infrastructure they support.

Q. Please describe the classification and allocation of customer accounts and customer service expenses in the COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. One exception to this treatment was FERC Account 904 (Uncollectible Accounts). Uncollectible Accounts expenses were assigned to the customer classes based on number of customers for Residential and GS-1 classes.

Q. Please explain the treatment of Administrative and General ("A&G") expenses in the COSS.

A. The A&G expenses were classified and allocated based on the internally generated allocation factor of total O&M expenses. Taxes Other than Income Taxes and their corresponding allocation basis include Property taxes, and Payroll, and Other taxes. Income taxes were allocated based on rate base. Income taxes were recalculated under both current and proposed revenue scenarios by class to reflect the corresponding level of operating income in each case.

F. COST OF SERVICE RESULTS

Q. Please summarize the results of the Company's proposed COSS.

A. Table 3 below presents a summary of the results of the COSS and presents the revenue deficiency/(surplus) for each rate class and the class rate of return at present rates. The study indicates an overall revenue requirement of approximately $157.1 million and a total revenue deficiency of $63.3 million. A portion of this deficiency reflects the inclusion of costs associated with assets currently recovered through the SAFE rider, which are proposed to be rolled into base rates. The revenue requirement associated with these SAFE assets is approximately $16.4 million, based on the overall revenue requirement assumptions. As discussed further in my testimony, the revenue requirement related to SAFE assets is accounted for separately in determining the overall revenue increase and is netted against the total deficiency.

Table 3 – FCG's Proposed COSS Result[5]

Line No.	Proposed Customer Class	Current Revenues	Cost to Serve	Class Revenue Deficiency/ (Excess)	Percentage Change to Cost to Serve	Proposed Revenues Changes ($)	Proposed Revenues Changes (%)	Rate of Return	Relative Rate of Return
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RS	$ 39,585,613	$ 81,320,165	$ 41,734,552	105.43%	$ 31,296,050	79.06%	-2.24%	(1.12)
2	RSG	23,969	52,799	28,830	120.28%	28,830	120.28%	-2.89%	(1.44)
3	GS - 1	15,792,573	23,862,015	8,069,442	51.10%	13,591,888	86.07%	4.19%	2.10
4	GS - 2 (10K)	13,949,880	20,440,141	6,490,261	46.53%	11,109,963	79.64%	4.98%	2.49
5	GS - 3 (50K)	3,057,787	4,586,579	1,528,792	50.00%	2,366,023	77.38%	4.69%	2.34
6	GS - 4 (120K)	12,920,273	22,404,329	9,484,056	73.40%	3,917,876	30.32%	2.79%	1.40
7	GS - 5 (1250K)	3,653,286	4,000,999	347,713	9.52%	398,294	10.90%	10.09%	5.04
8	GS - 6 (11M)	-	-	-	0.00%	-	0.00%	0.00%	-
9	GS - 7 (25M)	-	-	-	0.00%	-	0.00%	0.00%	-
10	GL	-	-	-	0.00%	-	0.00%	0.00%	-
11	CSG	59,765	390,157	330,392	552.82%	330,392	552.82%	-7.98%	(3.99)
12	Special Contracts	4,740,162		(4,740,162)	-100.00%	234,560	4.95%	0.00%	-
13	**Total**	**$ 93,783,308**	**$ 157,057,184**	**$ 63,273,876**	**67.47%**	**$ 63,273,876**	**67.47%**	2.00%	1.00

Q. Have you prepared a summary of COSS results that apply a demand-based classification of distribution mains??

A. Yes. **Table 4** compares the COSS results under two methodologies: the Supplemental COSS, which applied a demand-based classification of distribution mains, and the proposed COSS in the current case, which applies a customer/demand classification of distribution mains. As the results demonstrate, despite refinements in methodology and adjustments to cost classification and allocation for distribution mains, the results remain fundamentally consistent. The same customer classes continue to exhibit deficiencies, reaffirming the persistence of cost recovery imbalances.

[5] Reference: Schedule H-1 / Proposed Rate Design - Schedule B

Table 4 – Comparison of the COSS Methods

Line No.	Proposed Customer Class	Current Revenues	Proposed COSS - Customer/Demand Classification of Distribution Mains			Supplemental COSS - Demand-Based Classification of Distribution Mains		
			Cost to Serve	Class Revenue Deficiency/(Excess)	Percentage Change to Cost to Serve	Cost to Serve	Class Revenue Deficiency/(Excess)	Percentage Change to Cost to Serve
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RS	$ 39,585,613	$ 81,320,165	$ 41,734,552	105.4%	$ 67,078,672	$ 27,493,059	69.5%
2	RSG	23,969	52,799	28,830	120.3%	42,375	18,406	76.8%
3	GS - 1	15,792,573	23,862,015	8,069,442	51.1%	26,912,251	11,119,679	70.4%
4	GS - 2 (10K)	13,949,880	20,440,141	6,490,261	46.5%	24,745,526	10,795,645	77.4%
5	GS - 3 (50K)	3,057,787	4,586,579	1,528,792	50.0%	5,656,035	2,598,248	85.0%
6	GS - 4 (120K)	12,920,273	22,404,329	9,484,056	73.4%	28,194,942	15,274,669	118.2%
7	GS - 5 (1250K)	3,653,286	4,000,999	347,713	9.5%	4,036,449	383,163	10.5%
8	GS - 6 (11M)	-	-	-	0.0%	-	-	0.0%
9	GS - 7 (25M)	-	-	-	0.0%	-	-	0.0%
10	CSG	59,765	390,157	330,392	552.8%	390,934	331,170	554.1%
11	Special Contracts	4,740,162		(4,740,162)	-100.0%	-	(4,740,162)	
12	**Total**	**$ 93,783,308**	**$ 157,057,184**	**$ 63,273,876**	**67.5%**	**$ 157,057,184**	**$ 63,273,876**	**67.5%**

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. What guiding principles inform FCG'S rate design proposals?

A. FCG's rates seek to balance a number of policy objectives for its customers while providing the Company the ability to recover its prudently incurred costs and an opportunity to earn its authorized ROR. The following rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in his work, Principles of Public Utility Rates. Each of these principles plays an important role in analyzing the rate design proposals of FCG and provides a roadmap that help guide utilities and regulators when considering how to achieve utility rates that are fair, efficient and practical. The foundation of rates should include:

- Fairness: Rates should be fair to all customer classes, avoiding undue discrimination.

- Efficiency: Rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use.
- Value of Service: The value of service acts as a ceiling on prices. If rates exceed the value customers place on utility service, customers will reduce consumption or avoid the service altogether.
- Simplicity: Rates should be simple and understandable for customers.
- Stability: Rates should provide revenue stability for the utility and bill stability for customers.
- Reflective of Costs: Rates should reflect the cost of providing service to different customer classes.
- Revenue Sufficiency: Rates should generate enough revenue to cover the utility's costs, including a reasonable return on investment.

Q. How are these principles translated into the design of rates?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

VII. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe how you began your analysis of the revenue apportionment process.

A. In developing the revenue apportionment analysis, I first adjusted the Company's current revenue levels to reflect the inclusion of SAFE-related revenues associated with assets being rolled into base rates. These revenues were determined using the Company's proposed rate of return and other applicable rate case assumptions to ensure consistency with the requested revenue requirement. The resulting adjusted revenue levels are presented in Exhibit JT-3, which serves as the foundation for the subsequent apportionment analysis.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of FCG interclass revenue proposal?

A. Yes. Using the overall revenue increase proposed by FCG and the results of the COSS, multiple approaches were evaluated for allocating the increase among customer classes. These options were developed and reviewed in coordination with FCG personnel and management, ultimately leading to the selection of a preferred approach. As an initial benchmark, I evaluated a fully cost-based allocation in which each customer class's revenues were set equal to its respective cost to serve, as derived from the methodologies employed in the FCG Proposed COSS (see Exhibit JT-3). While this method provides a clear theoretical benchmark grounded in cost causation principles, it was determined, as a matter of judgment, that moving all classes directly to unity was not the preferred outcome for all classes due to potential rate impacts. However, for certain classes, revenues were increased to align with their cost to serve, as will be discussed later in my testimony. The results of this analysis nevertheless served as an important reference point for assessing the reasonableness of other allocation methods.

A second option considered was to allocate the proposed revenue increase across all customer classes on an equal percentage basis relative to their current revenues. By design, this approach results in uniform percentage increases for all classes.

While neither the fully cost-based approach nor the equal percentage increase approach was ultimately adopted in full, together they established a reasonable range of outcomes. This range provided a structured framework to guide the development of the Company's final interclass revenue allocation proposal, balancing revenue increase requirement, cost causation principles, rate stability, potential bypass risks considerations, and customer impact considerations.

Q. What was the result of this process?

A. The result of this process is a structured and balanced interclass revenue allocation approach that reflects cost of service principles while maintaining rate stability considering the overall system revenue increase requirement. The Company developed a set of guiding principles to ensure that revenue adjustments are allocated in a fair, transparent, and practical manner across customer classes.

The key principles underlying this approach are as follows:

Principle 1: Limit on Maximum Increases – No customer class is assigned an increase greater than 2 times the net system-wide percentage increase.

Principle 2: Alignment of Standby Generation Classes with Cost of Service – Residential and commercial standby generation classes are moved toward, or brought to, their respective cost to serve.

Principle 3: Residential Class Revenue Increase Moderation – The residential class increase is capped at 0.7 times the system-wide increase, or approximately 30 percent, to mitigate bill impacts for this class.

Principle 4: Commercial Class Revenue Increase Moderation – GS-4 (120K): The revenue increase for the GS-4 (120K) class was limited to approximately 30 percent. This approach was adopted in response to the Company's assessment of heightened customer sensitivity within this class, including the potential for load loss due to alternative fuel options and bypass risk.

Principle 5: Minimum Increase Threshold – No class is assigned an increase lower than 0.25 times the net system-wide percentage increase.

Principle 6: Redistribution of Remaining Revenue Requirement – Any remaining revenue requirement, after applying the above considerations is allocated to GS-1, GS-2 (10K), and GS-3 (50K) classes such that each class received the same percentage increase in revenues.

In addition, revenue adjustments for the Special Contracts customer group reflect the terms of existing contractual agreements, which are generally tied to applicable tariff rate schedules.

Table 5 - Proposed Class Revenue Apportionment

Line No.	Proposed Customer Class	Current Revenues	Transfer of Safe Investments Revenues	Total Revenue	Cost to Serve	Class Revenue Deficiency/(Excess)	Percentage Change to Cost to Serve	System Multiple	% Increase	Proposed Revenue Change	Revenue Apport. Principles
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	RS	$ 37,874,673	$ 15,167,225	$ 53,041,898	$ 79,609,225	$ 26,567,327	50.1%	0.70	30.4%	$ 16,128,826	Principle 3
2	RSG	23,200	-	23,200	52,030	28,830	124.3%	2.86	124.3%	28,830	Principle 2
3	GS - 1	15,471,170	944,340	16,415,510	23,540,612	7,125,103	43.4%	1.77	77.0%	12,647,548	Principle 1, 6
4	GS - 2 (10K)	13,829,899	256,731	14,086,630	20,320,160	6,233,530	44.3%	1.77	77.0%	10,853,231	Principle 1, 6
5	GS - 3 (50K)	3,032,595	16,674	3,049,269	4,561,387	1,512,118	49.6%	1.77	77.0%	2,349,350	Principle 1, 6
6	GS - 4 (120K)	12,813,395	16,576	12,829,972	22,297,451	9,467,480	73.8%	0.70	30.4%	3,901,300	Principle 4
7	GS - 5 (1250K)	3,653,286	1,399	3,654,685	4,000,999	346,314	9.5%	0.25	10.9%	396,895	Principle 5
8	GS - 6 (11M)	-	-	-	-	-	0.0%	-	0.0%	-	
9	GS - 7 (25M)	-	-	-	-	-	0.0%	-	0.0%	-	
10	CSG	57,804	-	57,804	388,197	330,392	571.6%	13.16	571.6%	330,392	Principle 2
11	Special Contracts	4,740,162		4,740,162		(4,740,162)	-100.0%		4.9%	234,560	Other
12	Total	$ 91,496,185	$ 16,402,944	$107,899,129	$ 154,770,062	$ 46,870,932	43.4%	1.00	43.4%	$ 46,870,932	

Q. Please discuss the increases to the standby generation service classes.

A. The Company is proposing to increase rates for the residential and commercial standby generation service classes in order to move these classes toward full cost recovery.

Under the current rate design, the customer charges applicable to standby generation customers are set at levels that do not adequately reflect the costs the Company incurs to connect, maintain service availability, and provide backup supply when customer-owned generation is not operating.

Unlike standard customers, standby generation customers rely on the Company's system both for supplemental energy and as a reliable backup resource. This requires the Company to maintain sufficient infrastructure and capacity to serve these customers on demand, even if their usage is intermittent or reduced. However, the existing charges do not appropriately recover these fixed and capacity-related costs, resulting in an under-recovery from these classes.

The proposed increases are therefore intended to better align rates with cost causation principles by ensuring that standby generation customers contribute an appropriate share of the costs they impose on the system. This change also mitigates potential cross-subsidization, where non-standby customers would otherwise bear a portion of the costs associated with serving standby generation customers.

Q. Has bill impact been reviewed for these customers?

A. Yes. The Company evaluated the bill impacts associated with the proposed changes to the standby generation service classes and recognizes that certain customers may experience relatively larger percentage increases compared to other classes. These impacts are primarily driven by the movement toward full cost recovery, as existing rates have historically under-collected the costs required to serve these customers.

While the magnitude of the increases may appear significant, it is important to consider the characteristics of customers taking standby generation service. These customers

have made discretionary investments in on-site generation equipment—such as backup generators—to enhance reliability and maintain service continuity during outages. Such investments generally indicate a higher level of financial capability and a willingness to incur additional costs to achieve improved service reliability. Accordingly, the Company does not expect the resulting rate changes to be unduly burdensome for these customers. Rather, the adjustments represent a necessary step to align rates with cost causation principles and to reduce cross-subsidization from other customer classes.

VIII. PROPOSED RATE DESIGN

A. CUSTOMER AND DEMAND CHARGES

Q. Please describe the process to determine the proposed changes to the Customer Charges and the other rate components for the respective tariff schedules.

A. Once revenue targets per class are set, the process of determining the rate components for each tariff schedule begins with establishing the Customer and Demand Charges. Once the Customer and Demand Charges were set, the revenues to be recovered through this charge for each rate schedule were deducted from the class revenue requirement targets. The remaining revenue requirement was then allocated to the Distribution Charge, which was calculated by dividing the remaining revenue by the projected sales volume under the applicable rate schedule.

Q. Please further discuss the importance of the Customer Charge component.

A. To properly recover fixed costs that the utility incurs to provide service to its customers, the Customer Charge component of each rate schedule needs to be set at or near the cost per customer component identified in the COSS.

The customer-based charge can be characterized as a connection charge for access to service. It is imperative that appropriate fixed costs be collected through the monthly charge in order to minimize intra-class subsidies and provide customers with the appropriate economic price signals. Increasing the Customer Charge to the amount identified as necessary to recover at least the customer-related fixed costs does not provide a disincentive to use energy wisely. Customers' conservation efforts are rewarded through lower bills because of lower energy consumption. Other benefits of better aligning cost recovery with cost causation include:

- Mitigating the impact of significantly colder or warmer than normal weather on customers' bills;
- Mitigating the impact abnormal weather has on the Company's ability to recover fixed costs in the customers' regular monthly bills;
- Providing more stability in residential customers' bills as a higher percentage of the total bill will be fixed each month and not subject to changes in weather; and
- Providing a better match of revenues to the investment made to serve each customer.

If fixed costs are not recovered from fixed charges, average or higher than average use customers subsidize low use customers, regardless of the reason a customer uses less gas than average.

Q. How were proposed monthly customer changes determined?

A. The proposed customer charge adjustments were determined by considering multiple factors. The customer-related unit cost, as calculated in MFR Schedule H-1, served as the baseline. The proposed customer charge for residential classes reflects a strategic effort to consolidate rate classes and ensure that fixed costs are more accurately

recovered while considering bill impacts. In general, the customer charge rates were adjusted to align more closely with the unit cost.

Table 6 below summarizes the results of the customer costs in the COSS and compares them to FCG'S current customer charges.

Table 6 – Customer Charge Compared to Current, Proposed and Unit Cost

Line No.	Current Customer Class	Comparable Proposed Customer Class	Current Customer Charge	Proposed Customer Charge	Customer Related Unit Cost
	(1)	(2)	(3)	(4)	(5)
1	RS-1	RS	$ 18.00	$ 36.50	$ 45.35
2	RS-100	RS	$ 19.00	$ 36.50	$ 45.35
3	RS-600	RS	$ 25.00	$ 36.50	$ 45.35
4	GS-1	GS - 1	$ 31.00	$ 85.00	$ 117.10
5	GS-6K	GS - 2 (10K)	$ 44.00	$ 155.00	$ 261.07
6	GS-25K	GS - 3 (50K)	$ 188.00	$ 600.00	$ 715.35
7	GS-120K	GS - 4 (120K)	$ 375.00	$ 750.00	$ 1,549.84
8	GS-1250K	GS - 5 (1250K)	$ 625.00	$ 1,250.00	$ 5,073.07
9	GS-11M	GS - 6 (11M)	$ 1,250.00	$ 2,500.00	$ -
10	GS-25M	GS - 7 (25M)	$ 2,500.00	$ 5,000.00	$ -
11	RSG	RSG	$ 25.00	$ 54.27	$ 54.35
12	CSG	CSG	$ 36.00	$ 231.58	$ 230.51

Q. Have you provided a schedule detailing the proposed rates and corresponding revenues?

A. Yes. MFR Schedule H-1 Schedule A contains the proposed customer and demand charges, volumetric charges and the corresponding revenues generated for each of the proposed rate classes. Each of these three sections follows the same format of developing rates. First, the portion of revenues recovered through the customer and demand charges is calculated. Then, the remaining targeted revenues are recovered through the volumetric charges.

Q. What are the corresponding bill comparisons for FCG customers?

A. As required by MFR Schedule E-5, the Company's prepared total bill impacts for each

of the rate classes.

B. ALTERNATIVE ENTERPRISE RESOURCE PLANNING ("ERP") REVENUE RECOVERY MECHANISM (STEP RATE APPROACH)

Q. Please discuss the development of base rates under the Company's proposed ERP revenue requirement recovery.

A. The Company's filing reflects recovery of the full ERP -related revenue requirement. However, if the Commission does not approve recovery for a full year, the Company proposes, as an alternative, to exclude the ERP-related revenue requirement from the rates implemented January 1, 2027, as discussed by witness Ms. Baugh.

Under this alternative, rates would initially be set excluding this amount, as illustrated on Exhibit JT-4. Once the ERP system is placed into service, the Company would implement a step rate increase, expected approximately mid-year 2027, to incorporate the ERP-related revenue requirement.

IX. SUMMARY

Q. Please summarize your conclusions and recommendations.

A. The proposals presented in my testimony are designed to provide Florida City Gas Company with a fair and reasonable opportunity to recover its prudently incurred costs while advancing rate structures that better reflect cost causation, promote revenue stability, and moderate customer impacts.

Forecasted billing determinants and projected test year revenues were developed using weather-normalized usage and customer forecasts that reasonably reflect expected operating conditions. These billing determinants form the foundation for evaluating revenue adequacy under present rates and for designing the proposed rates.

An embedded Class Cost of Service Study was developed using the Commission's required MFR H model. The COSS incorporates refinements to the classification and allocation of distribution mains through a phased Customer/Demand methodology for small-diameter mains, while retaining established methods for larger facilities. This approach improves alignment between cost responsibility and the underlying drivers of system investment while maintaining consistency with prior Commission precedent.

Based on the COSS results, a balanced allocation of the requested revenue increase among customer classes was developed. This allocation reflects cost of service principles while incorporating stability through the use of caps, floors, and residential moderation to mitigate rate impacts. Certain classes, including standby generation customers, are moved closer to their cost to serve, and Special Contract revenues are treated consistent with their contractual arrangements.

In conjunction with the proposed revenue allocation, several rate structure and rate design changes were developed, including consolidation of residential classes, adjustments to commercial class applicability thresholds, elimination of unused rate schedules, and revisions to customer and demand charges. Customer charges are moved closer to the customer-related costs identified in the COSS, with remaining revenues recovered through volumetric distribution charges, improving cost alignment.

Taken together, these proposals represent a reasonable and coordinated approach to revenue recovery, cost allocation, and rate design. They support the requested rate relief while enhancing alignment with cost causation principles, promoting

administrative efficiency, and maintaining rate stability for customers.

Q. Does this conclude your prepared direct testimony?

A. Yes.

MFR Schedule	Page No.	MFR Title
E-01	P. 1-2	Cost of Service: Therm Sales and Revenue by Rate Schedule Under Present Rates and under Present and Proposed Rate Class Schedule
E-01	P. 3	Cost of Service: Therm Sales and Revenue by Rate Schedule Under Present Rates, Adjusted for Growth in Bills and Therms, Without Rate Increase
E-01	P. 4	Cost of Service: Therm Sales and Revenue by Rate Schedule Under Proposed Rates
E-02		Cost of Service: Provide Revenues Calculated at Present Rates, Present Rates Adjusted for Growth Only for the Projected Test Year, and Final Rates Historic Base Year Data
E-04		Cost of Service - System Peak Month Sales by Rate Class
E-05	P. 1-4	Cost of Service – FCG Residential/Monthly Bill Comparison
E-05	P. 5-6	Cost of Service – FCG GS-1 Monthly Bill Comparison
E-05	P. 7-8	Cost of Service – FCG GS-2 (10-K) Monthly Bill Comparison
E-05	P. 9	Cost of Service – FCG GS-3 (50K) Monthly Bill Comparison
E-05	P. 10	Cost of Service – FCG Commercial Standby Generator (CSG)Monthly Bill Comparison
E-05	P. 11	Cost of Service –FCG GS-4 (120K)Monthly Bill Comparison
E-05	P. 12	Cost of Service –FCG GS-5 (1250K) Monthly Bill Comparison
E-05	P. 13	Cost of Service – FCG GS-6 (11M) Monthly Bill Comparison
E-05	P. 14	Cost of Service – FCG GS-7 (25M) Monthly Bill Comparison
E-07	P. 1	Cost Study – Meter Set
E-08	P. 1	Cost Study – Derivation of Facilities
G-02	P. 8	Projected Test Year – Revenues and Cost of Gas at Current Rates
G-02	P. 9	Projected Test Year – Revenues and Cost of Gas at Proposed Rates
H-01	P. 1 Schedule A	Cost of Service – Fully Allocated Embedded
		Cost of Service – Proposed Rates
H-01	P. 2 Schedule B	Cost of Service – Fully Allocated Embedded
		Cost of Service – Proposed Rate Design
H-01	P. 3 Schedule C	Cost of Service – Fully Allocated Embedded
		Cost of Service – Rate of Return By Class
H-01	P. 4 Schedule C	Cost of Service – Fully Allocated Embedded
		Cost of Service – Rate of Return By Class (Cont.) Proposed Rates
H-01	P. 5 Schedule D	Cost of Service – Fully Allocated Embedded
		Cost of Service – Revenue Deficiency
H-01	P. 6	Cost of Service – Fully Allocated Embedded
		Cost of Service – Summary
H-02	P. 1, 6	Fully Allocated Embedded Cost of Service – Summary
H-02	P. 2Schedule E (2 of 2)	Fully Allocated Embedded Cost of Service – Allocation of Cost of Service to Customer Classes
H-02	P. 3 Schedule E (1 of 2)	Fully Allocated Embedded Cost of Service – Allocation of Cost of Service to Customer Classes (Cont.)
H-02	P. 4 Schedule F	Fully Allocated Embedded Cost of Service – Allocation of Rate Base to Customer Classes
H-02	P. 5 Schedule G	Fully Allocated Embedded Cost of Service – Development of Allocation Factors
H-03	P. 1	Fully Allocated Embedded Cost of Service – Summary
H-03	P. 2 Schedule H (1 of 2)	Fully Allocated Embedded Cost of Service– Classification of Expenses and Derivation of Cost of Service By Cost
H-03	P. 3 Schedule H (2 of 2)	Fully Allocated Embedded Cost of Service – Classification of Expenses and Derivation of Cost of Service By Cost (Cont.)
H-03	P. 4 Schedule I (2 of 2)	Fully Allocated Embedded Cost of Service – Classification of Rate Base - Accumulated Depreciation
H-03	P. 5 Schedule I (1 of 2)	Fully Allocated Embedded Cost of Service – Classification of Rate Base – Plant
H-03	P. 3	Cost of Service – Fully Allocated Embedded
		Cost of Service – Classification of O&M Expenses
H-03	P. 4	Cost of Service – Fully Allocated Embedded
		Cost of Service – Classification of Depreciation and Tax Expense
H-03	P. 5	Cost of Service – Fully Allocated Embedded
		Cost of Service – Summary

Schedule H-1 | Cost of Service | Page 1 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Calculation of Proposed Rates
Schedule A

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
1	PROPOSED TOTAL TARGET REVENUES	$ 157,057,184	$ 70,881,663	$ 52,799	$ 29,384,460	$ 25,059,843	$ 5,423,810	$ 16,838,150	$ 4,051,580	$ -	$ -	$ 390,157	$ 3,480,790	$ 280,181	$ 1,213,751
2	LESS:OTHER OPERATING REVENUE	$ 2,287,122	$ 1,710,939	$ 769	$ 321,403	$ 119,982	$ 25,192	$ 106,878	$ -	$ -	$ -	$ 1,960	$ -	$ -	$ -
	LESS:CUSTOMER CHARGE REVENUES														
3	PROPOSED CUSTOMER CHARGES		$ 36.50	$ 54.27	$ 85.00	$ 155.00	$ 600.00	$ 750.00	$ 1,250.00	$ 2,500.00	$ 5,000.00	$ 231.58			
4	TIMES:NUMBER OF BILLS	1,596,372	1,449,276	928	85,722	19,444	1,237	1,236	104	-	-	1,606	36	36,747	36
5	EQUALS:CUSTOMER CHARGE REVENUES	65,419,584	52,898,583	50,358	7,286,392	3,013,892	741,932	927,033	129,555	-	-	371,838	-		
6	LESS:DEMAND CHARGE REVENUES														
7	PROPOSED DEMAND CHARGES							$ 0.92517	$ 0.92517	$ 0.92517	$ 0.92517				
8	TIMES: DCQ SALES							3,053,952	1,574,040						
9	EQUALS: DEMAND CHARGE REVENUES	4,281,658	-	-	-	-	-	2,825,410	1,456,247	-	-	-	-	-	-
10	EQUALS:PER-THERM TARGET REVENUES	85,068,820	16,272,140	1,672	21,776,665	21,925,969	4,656,686	12,978,829	2,465,778	-	-	16,358	3,480,790	280,181	1,213,751
11	DIVIDED BY:NUMBER OF THERMS	127,173,088	17,783,310	1,827	23,326,615	26,392,437	6,357,270	35,834,584	17,457,355	-	-	19,691	-	-	-
12	EQUALS:PER-THERM RATES(UNRNDED)		0.91502	0.91502	0.93355	0.83077	0.73250	0.36219	0.14125	0.10358	0.05179	0.83077	-	-	-
13	PER-THERM RATES(RNDED)		**0.91502**	**0.91502**	**0.93355**	**0.83077**	**0.73250**	**0.36219**	**0.14125**	**0.10358**	**0.05179**	**0.83077**	**-**	**-**	**-**
14	PER-THERM-RATE REVENUES(RNDED RATES)	77,611,990	16,272,084	1,672	21,776,561	21,926,045	4,656,700	12,978,928	2,465,851	-	-	16,358	-	-	-
	SUMMARY:PROPOSED TARIFF RATES														
15	CUSTOMER CHARGES		$ 36.50	$ 54.27	$ 85.00	$ 155.00	$ 600.00	$ 750.00	$ 1,250.00	$ 2,500.00	$ 5,000.00	$ 231.58	$ -	$ -	$ -
	DEMAND CHARGES							$ 92.52	$ 92.52	$ 92.52	$ 92.52				
16	ENERGY CHARGES														
17	NON-GAS (CENTS PER THERM)		$ 91.50200	$ 91.50200	$ 93.35500	$ 83.07700	$ 73.25000	$ 36.21900	$ 14.12500	$ 10.35800	$ 5.17900	$ 83.07700	$ -	$ -	$ -
18	PURCHASED GAS ADJUSTMENT		$ 127.69000	$ 127.69000	$ 127.69000	$ 127.69000	$ 127.69000	$ 127.69000	$ -	$ -	$ -	$ 127.69000	$ -	$ -	$ -
19	TOTAL (INCLUDING PGA)		$ 219.19200	$ 219.19200	$ 221.04500	$ 210.76700	$ 200.94000	$ 163.90900	$ 14.12500	$ 10.35800	$ 5.17900	$ 210.76700	$ -	$ -	$ -
	SUMMARY:PRESENT TARIFF RATES														
20	CUSTOMER CHARGES		$18.00, $19.00, $25.00	$ 25.00	$31.00, $44.00	$44.00, $188.00	$ 188.00	$ 375.00	$ 625.00	$ 1,250.00	$ 2,500.00	$ 36.00	$ -	$ -	$ -
	DEMAND CHARGES							$ 0.71900	$ 0.71900	$ 0.71900	$ 0.71900				
	ENERGY CHARGES														
21	NON-GAS (CENTS PER THERM)		$0.67667, $0.57421, $0.70799	$ 0.57421	$0.57949, $0.48722	$0.48722, $0.44046	$ 0.44046	$ 0.28336	$ 0.14073	$ 0.10320	$ 0.05160	$ 0.57949			
22	PURCHASED GAS ADJUSTMENT		$ 1.27690	$ 1.27690	$ 1.27690	$ 1.27690	$ 1.27690	$ 1.27690	$ -	$ -	$ -	$ 1.27690	$ -	$ -	$ -
23	TOTAL (INCLUDING PGA)		$1.95357, $1.85111, $1.98489	$ 1.85111	$1.85639, $1.76412	$1.76412, $1.71736	$ 1.71736	$ 1.56026	$ 0.14073	$ 0.10320	$ 0.05160	$ 1.85639	$ -	$ -	$ -
	SUMMARY:OTHER OPERATING REVENUE														
24	Water Heater Interest**	$225,320	$97,464	$10	$127,845	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
25	Late Payment Charges**	$1,142,643	$879,572	$440	$105,797	$70,689	$15,451	$69,639	$0	$0	$0	$1,055	$0	$0	$0
26	MISCELLANEOUS SERVICE REVENUE*	$826,685	$657,070	$319	$78,873	$44,671	$9,341	$35,506	$0	$0	$0	$905	$0	$0	$0
27	NSF Charges**	$92,475	$76,833	$0	$8,888	$4,622	$400	$1,733	$0	$0	$0	$0	$0	$0	$0
28	Total	$2,287,122	$1,710,939	$769	$321,403	$119,982	$25,192	$106,878	$0	$0	$0	$1,960	$0	$0	$0

		PRESENT		PROPOSED	
	*MISCELLANEOUS SERVICE REVENUE	Charge	Revenue	Charge	Revenue
29	Connection - Residential	$90.00	$232,810	$95.00	$153,995
30	Connection - Non Residential	$150.00	$24,150	$150.00	$97,200
31	Reconnection - Residential	$90.00	$480,780	$90.00	$301,140
32	Reconnection - Non Residential	$105.00	$24,780	$120.00	$10,680
33	Temporary Disconnection of Service	$35.00	$3,150	$55.00	$19,250
34	Change of Account (Read Meter Only)	$20.00	$141,900	$55.00	$244,420
35	TOTAL		$907,570		$826,685

**Other Operating Revenues excluding Miscellaneous Service Revenues are based on historical billed revenues from FCG's billing system and are not calculated by multiplying rates x # of occurrences.

Supporting Schedules: E-2 p.1, E-3 p.1-6, H-1 p.2 | Recap Schedules:

Schedule H-1 | Cost of Service | Page 2 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Proposed Rate Design
Schedule B

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	PRESENT RATES (projected test year)														
1	GAS SALES (due to growth)	$ 91,496,185	$ 37,874,673	$ 23,200	$ 15,471,170	$ 13,829,899	$ 3,032,595	$ 12,813,395	$ 3,653,286	$ -	$ -	$ 57,804	$ 3,246,230	$ 280,181	$ 1,213,751
2	OTHER OPERATING REVENUE	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
3	TOTAL	$ 93,783,308	$ 39,585,613	$ 23,969	$ 15,792,573	$ 13,949,880	$ 3,057,787	$ 12,920,273	$ 3,653,286	$ -	$ -	$ 59,765	$ 3,246,230	$ 280,181	$ 1,213,751
4	RATE OF RETURN	2.00%	-0.14%	-0.81%	2.54%	2.41%	1.98%	0.30%	9.88%	0.00%	0.00%	-8.34%	0.00%	0.00%	0.00%
5	INDEX	1.00	(0.07)	(0.41)	1.27	1.20	0.99	0.15	4.94	-	-	(4.17)	-	-	-
	STAFF PROPOSED RATES														
6	GAS SALES	$ 154,770,062	$ 65,367,732	$ 41,606	$ 26,590,849	$ 24,625,544	$ 5,630,843	$ 28,088,064	$ 4,036,449	$ -	$ -	$ 388,974	$ -	$ -	$ -
7	OTHER OPERATING REVENUE	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
8	TOTAL	$ 157,057,184	$ 67,078,672	$ 42,375	$ 26,912,251	$ 24,745,526	$ 5,656,035	$ 28,194,942	$ 4,036,449	$ -	$ -	$ 390,934	$ -	$ -	$ -
9	TOTAL REVENUE INCREASE	$ 63,273,876	$ 27,493,059	$ 18,406	$ 11,119,679	$ 10,795,645	$ 2,598,248	$ 15,274,669	$ 383,163	$ -	$ -	$ 331,170	$ (3,246,230)	$ (280,181)	$ (1,213,751)
10	PERCENT INCREASE	67.47%	69.45%	76.79%	70.41%	77.39%	84.97%	118.22%	10.49%	0.00%	0.00%	554.12%	-100.00%	-100.00%	-100.00%
11	RATE OF RETURN	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	0.00%	0.00%	8.31%	0.00%	0.00%	0.00%
12	INDEX	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	-	-	1.00	-	-	-
	FCG PROPOSED RATES														
13	GAS SALES	$ 154,770,062	$ 69,170,724	$ 52,030	$ 29,063,058	$ 24,939,861	$ 5,398,618	$ 16,731,272	$ 4,051,580	$ -	$ -	$ 388,197	$ 3,480,790	$ 280,181	$ 1,213,751
14	OTHER OPERATING REVENUE	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
15	TOTAL	$ 157,057,184	$ 70,881,663	$ 52,799	$ 29,384,460	$ 25,059,843	$ 5,423,810	$ 16,838,150	$ 4,051,580	$ -	$ -	$ 390,157	$ 3,480,790	$ 280,181	$ 1,213,751
16	TOTAL REVENUE INCREASE	$ 63,273,876	$ 31,296,050	$ 28,830	$ 13,591,888	$ 11,109,963	$ 2,366,023	$ 3,917,876	$ 398,294	$ -	$ -	$ 330,392	$ 234,560	$ -	$ -
17	PERCENT INCREASE	67.47%	79.06%	120.28%	86.07%	79.64%	77.38%	30.32%	10.90%	0.00%	0.00%	552.82%	7.23%	0.00%	0.00%
18	RATE OF RETURN	8.31%	9.47%	13.33%	9.77%	8.50%	7.69%	2.28%	8.37%	0.00%	0.00%	8.28%	0.00%	0.00%	0.00%
19	INDEX	1.00	1.14	1.60	1.18	1.02	0.93	0.27	1.01	-	-	1.00	-	-	-

Supporting Schedules: H-1 p.3, H-1 p.4

Recap Schedules:

Schedule H-1 | Cost of Service | Page 3 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Rate of Return by Customer Class
Schedule C Page 2 of 2

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	EQUAL ROR														
1	REVENUES:														
2	Gas Sales	$ 154,770,062	$ 65,367,732	$ 41,606	$ 26,590,849	$ 24,625,544	$ 5,630,843	$ 28,088,064	$ 4,036,449	$ -	$ -	$ 388,974	$ -	$ -	$ -
3	Other Operating Revenue	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
4	Total	$ 157,057,184	$ 67,078,672	$ 42,375	$ 26,912,251	$ 24,745,526	$ 5,656,035	$ 28,194,942	$ 4,036,449	$ -	$ -	$ 390,934	$ -	$ -	$ -
	EXPENSES:														
5	Purchased Gas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	O&M Expenses	46,623,423	27,879,012	17,532	6,338,590	5,010,123	1,106,276	5,274,629	889,851	-	-	107,411	-	-	-
7	Depreciation Expenses	24,294,467	8,460,532	5,370	4,567,151	4,395,562	1,013,940	5,111,038	678,047	-	-	62,826	-	-	-
8	Amortization Expenses	22,157	3,467	0	4,024	4,594	1,109	6,105	2,854	-	-	3	-	-	-
9	Taxes Other Than Income--Fixed	12,104,772	4,252,534	2,669	2,254,984	2,173,721	501,866	2,537,125	351,617	-	-	30,257	-	-	-
10	Taxes Other Than Income--Revenue	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-
11	Total Expenses excl. Income Taxes	$ 81,130,311	$ 39,910,496	$ 25,137	$ 12,809,137	$ 11,243,545	$ 2,544,739	$ 12,534,004	$ 1,867,683	$ -	$ -	$ 195,572	$ -	$ -	$ -
12	PRE TAX NOI:	$ 75,926,872	$ 27,168,176	$ 17,238	$ 14,103,115	$ 13,501,980	$ 3,111,295	$ 15,660,939	$ 2,168,766	$ -	$ -	$ 195,362	$ -	$ -	$ -
13	INCOME TAXES:	$ 14,232,356	$ 5,092,626	$ 3,231	$ 2,643,604	$ 2,530,922	$ 583,207	$ 2,935,615	$ 406,531	$ -	$ -	$ 36,620	$ -	$ -	$ -
14	NET OPERATING INCOME:	$ 61,694,517	$ 22,075,550	$ 14,007	$ 11,459,511	$ 10,971,059	$ 2,528,089	$ 12,725,324	$ 1,762,235	$ -	$ -	$ 158,742	$ -	$ -	$ -
15	RATE BASE:	$ 742,412,954	$ 265,650,425	$ 168,557	$ 137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -
16	RATE OF RETURN	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	8.31%	0.00%	0.00%	8.31%	0.00%	0.00%	0.00%
	PROPOSED ROR														
	REVENUES:														
17	Gas Sales	$ 154,770,062	$ 69,170,724	$ 52,030	$ 29,063,058	$ 24,939,861	$ 5,398,618	$ 16,731,272	$ 4,051,580	$ -	$ -	$ 388,197	$ 3,480,790	$ 280,181	$ 1,213,751
18	Other Operating Revenue	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
19	Total	$ 157,057,184	$ 70,881,663	$ 52,799	$ 29,384,460	$ 25,059,843	$ 5,423,810	$ 16,838,150	$ 4,051,580	$ -	$ -	$ 390,157	$ 3,480,790	$ 280,181	$ 1,213,751
	EXPENSES:														
20	Purchased Gas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	O&M Expenses	46,623,423	27,879,012	17,532	6,338,590	5,010,123	1,106,276	5,274,629	889,851	-	-	107,411	-	-	-
22	Depreciation Expenses	24,294,467	8,460,532	5,370	4,567,151	4,395,562	1,013,940	5,111,038	678,047	-	-	62,826	-	-	-
23	Amortization Expenses	22,157	3,467	0	4,024	4,594	1,109	6,105	2,854	-	-	3	-	-	-
24	Taxes Other Than Income--Fixed	12,104,772	4,252,534	2,669	2,254,984	2,173,721	501,866	2,537,125	351,617	-	-	30,257	-	-	-
25	Taxes Other Than Income--Revenue	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-
26	Total Expenses excl. Income Taxes	$ 81,130,311	$ 39,910,496	$ 25,137	$ 12,809,137	$ 11,243,545	$ 2,544,739	$ 12,534,004	$ 1,867,683	$ -	$ -	$ 195,572	$ -	$ -	$ -
27	PRE TAX NOI:	$ 75,926,872	$ 30,971,168	$ 27,662	$ 16,575,324	$ 13,816,298	$ 2,879,071	$ 4,304,146	$ 2,183,897	$ -	$ -	$ 194,585	$ 3,480,790	$ 280,181	$ 1,213,751
28	INCOME TAXES:	$ 14,232,356	$ 5,805,490	$ 5,185	$ 3,107,015	$ 2,589,840	$ 539,677	$ 806,804	$ 409,368	$ -	$ -	$ 36,475	$ 652,468	$ 52,520	$ 227,515
29	NET OPERATING INCOME:	$ 61,694,517	$ 25,165,678	$ 22,477	$ 13,468,309	$ 11,226,457	$ 2,339,394	$ 3,497,342	$ 1,774,529	$ -	$ -	$ 158,111	$ 2,828,322	$ 227,662	$ 986,235
30	RATE BASE:	$ 742,412,954	$ 265,650,425	$ 168,557	$ 137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -
31	RATE OF RETURN	8.31%	9.47%	13.33%	9.77%	8.50%	7.69%	2.28%	8.37%	0.00%	0.00%	8.28%	0.00%	0.00%	0.00%

Supporting Schedules: E-1 p.3, H-1 p.5, H-1 p.6 | Recap Schedules: H-1 p.2

Schedule H-1 | Cost of Service | Page 4 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Rate of Return by Customer Class
Schedule C Page 1 of 2

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	REVENUES: (projected test year)														
1	Gas Sales (due to growth)	$ 91,496,185	$ 37,874,673	$ 23,200	$ 15,471,170	$ 13,829,899	$ 3,032,595	$ 12,813,395	$ 3,653,286	$ -	$ -	$ 57,804	$ 3,246,230	$ 280,181	$ 1,213,751
2	Other Operating Revenue	2,287,122	1,710,939	769	321,403	119,982	25,192	106,878	-	-	-	1,960	-	-	-
3	Total	$ 93,783,308	$ 39,585,613	$ 23,969	$ 15,792,573	$ 13,949,880	$ 3,057,787	$ 12,920,273	$ 3,653,286	$ -	$ -	$ 59,765	$ 3,246,230	$ 280,181	$ 1,213,751
	EXPENSES:														
4	Purchased Gas Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	O&M Expenses	46,623,423	27,879,012	17,532	6,338,590	5,010,123	1,106,276	5,274,629	889,851	-	-	107,411	-	-	-
6	Depreciation Expenses	24,294,467	8,460,532	5,370	4,567,151	4,395,562	1,013,940	5,111,038	678,047	-	-	62,826	-	-	-
7	Amortization Expenses	22,157	3,467	0	4,024	4,594	1,109	6,105	2,854	-	-	3	-	-	-
8	Taxes Other Than Income--Fixed	12,104,772	4,252,534	2,669	2,254,984	2,173,721	501,866	2,537,125	351,617	-	-	30,257	-	-	-
9	Taxes Other Than Income--Revenue	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-
10	Total Expenses excl. Income Taxes	$ 81,130,311	$ 39,910,496	$ 25,137	$ 12,809,137	$ 11,243,545	$ 2,544,739	$ 12,534,004	$ 1,867,683	$ -	$ -	$ 195,572	$ -	$ -	$ -
11	INCOME TAXES:	$ (2,195,887)	$ 56,382	$ 203	$ (517,766)	$ (469,676)	$ (89,038)	$ (67,036)	$ (309,886)	$ -	$ -	$ 23,569	$ (563,373)	$ (48,625)	$ (210,643)
12	NET OPERATING INCOME:	$ 14,848,883	$ (381,265)	$ (1,371)	$ 3,501,202	$ 3,176,011	$ 602,085	$ 453,306	$ 2,095,489	$ -	$ -	$ (159,376)	$ 3,809,603	$ 328,806	$ 1,424,393
13	RATE BASE:	$ 742,412,954	$ 265,650,425	$ 168,557	$ 137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -
14	RATE OF RETURN	2.00%	-0.14%	-0.81%	2.54%	2.41%	1.98%	0.30%	9.88%	0.00%	0.00%	-8.34%	0.00%	0.00%	0.00%

Supporting Schedules: E-1 p.2, H-1 p.5, H-1 p.6,

Recap Schedules:

Schedule H-1 | Cost of Service | Page 5 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated cost of service study. Fully allocated embedded cost of service.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Derivation Of Revenue Deficiency
Schedule D

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
1	CUSTOMER COSTS	$ 66,571,348	$ 48,613,335	$ 40,010	$ 9,339,009	$ 5,080,426	$ 914,333	$ 1,990,345	$ 225,674	$ -	$ -	$ 368,216	$ -	$ -	$ -
2	CAPACITY COSTS	88,708,768	16,113,425	2,031	17,529,020	19,885,573	4,794,962	26,492,613	3,865,460	-	-	25,684	-	-	-
3	COMMODITY COSTS	1,404,455	1,326,023	-	78,432	-	-	-	-	-	-	-	-	-	-
4	REVENUE COSTS	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-
5	TOTAL	$ 154,770,062	$ 65,367,732	$ 41,606	$ 26,590,849	$ 24,625,544	$ 5,630,843	$ 28,088,064	$ 4,036,449	$ -	$ -	$ 388,974	$ -	$ -	$ -
6	less: REVENUE AT PRESENT RATES (in the projected test year)	$ 91,496,185	$ 37,874,673	$ 23,200	$ 15,471,170	$ 13,829,899	$ 3,032,595	$ 12,813,395	$ 3,653,286	$ -	$ -	$ 57,804	$ 3,246,230	$ 280,181	$ 1,213,751
7	equals: GAS SALES REVENUE DEFICIENCY	$ 63,273,876	$ 27,493,059	$ 18,406	$ 11,119,679	$ 10,795,645	$ 2,598,248	$ 15,274,669	$ 383,163	$ -	$ -	$ 331,170	$ (3,246,230)	$ (280,181)	$ (1,213,751)
8	plus: DEFICIENCY IN OTHER OPERATING REV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	equals: TOTAL BASE-REVENUE DEFICIENCY	$ 63,273,876	$ 27,493,059	$ 18,406	$ 11,119,679	$ 10,795,645	$ 2,598,248	$ 15,274,669	$ 383,163	$ -	$ -	$ 331,170	$ (3,246,230)	$ (280,181)	$ (1,213,751)
	UNIT COSTS:														
10	Customer	$ 42.69	$ 33.54	$ 43.11	$ 108.94	$ 261.28	$ 739.42	$ 1,610.25	$ 2,177.40	$ -	$ -	$ 229.32	$ -	$ -	$ -
11	Capacity	$ 7.34	$ 7.70	$ 17.66	$ 8.07	$ 7.94	$ 7.91	$ 8.14	$ 2.66	$ -	$ -	$ 13.37	$ -	$ -	$ -
12	Commodity	$ 0.01	$ 0.07	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Supporting Schedules: E-1 p.2, H-1 p.6

Recap Schedules: H-1 p.2

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Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study (summary).

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	SUMMARY														
1	RB	$ 742,412,954	$ 265,650,425	$ 168,557	$137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -
2	ATTRITION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	O&M	$ 46,623,423	$ 27,879,012	$ 17,532	$ 6,338,590	$ 5,010,123	$ 1,106,276	$ 5,274,629	$ 889,851	$ -	$ -	$ 107,411	$ -	$ -	$ -
4	DEPRECIATION	$ 24,294,467	$ 8,460,532	$ 5,370	$ 4,567,151	$ 4,395,562	$ 1,013,940	$ 5,111,038	$ 678,047	$ -	$ -	$ 62,826	$ -	$ -	$ -
5	AMORTIZATION EXPENSES	$ 22,157	$ 3,467	$ 0	$ 4,024	$ 4,594	$ 1,109	$ 6,105	$ 2,854	$ -	$ -	$ 3	$ -	$ -	$ -
6	TAXES OTHER THAN INCOME - OTHER	$ 12,104,772	$ 4,252,534	$ 2,669	$ 2,254,984	$ 2,173,721	$ 501,866	$ 2,537,125	$ 351,617	$ -	$ -	$ 30,257	$ -	$ -	$ -
7	TAXES OTHER THAN INCOME - REV. RELATED	$ (1,914,508)	$ (685,050)	$ (435)	$ (355,612)	$ (340,455)	$ (78,452)	$ (394,893)	$ (54,686)	$ -	$ -	$ (4,926)	$ -	$ -	$ -
8	INCOME TAXES TOTAL	$ 14,232,356	$ 5,092,626	$ 3,231	$ 2,643,604	$ 2,530,922	$ 583,207	$ 2,935,615	$ 406,531	$ -	$ -	$ 36,620	$ -	$ -	$ -
9	REVENUE CREDITED TO COS:	$ (2,287,122)	$ (1,710,939)	$ (769)	$ (321,403)	$ (119,982)	$ (25,192)	$ (106,878)	$ -	$ -	$ -	$ (1,960)	$ -	$ -	$ -
10	TOTAL COST - CUSTOMER	$ 66,571,348	$ 48,613,335	$ 40,010	$ 9,339,009	$ 5,080,426	$ 914,333	$ 1,990,345	$ 225,674	$ -	$ -	$ 368,216	$ -	$ -	$ -
11	TOTAL COST - CAPACITY	$ 88,708,768	$ 16,113,425	$ 2,031	$ 17,529,020	$ 19,885,573	$ 4,794,962	$ 26,492,613	$ 3,865,460	$ -	$ -	$ 25,684	$ -	$ -	$ -
12	TOTAL COST - COMMODITY	$ 1,404,455	$ 1,326,023	$ -	$ 78,432	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	TOTAL COST - REVENUE	$ (1,914,508)	$ (685,050)	$ (435)	$ (355,612)	$ (340,455)	$ (78,452)	$ (394,893)	$ (54,686)	$ -	$ -	$ (4,926)	$ -	$ -	$ -
14	NO. OF CUSTOMERS	129,963	120,773	77	7,144	1,620	103	103	9	-	-	134	-	-	-
15	PEAK MONTH SALES	12,083,903	2,092,356	115	2,172,844	2,502,980	605,954	3,253,917	1,453,817	-	-	1,921	-	-	-
16	ANNUAL SALES	127,173,088	17,783,310	1,827	23,326,615	26,392,437	6,357,270	35,834,584	17,457,355	-	-	19,691	-	-	-

Supporting Schedules: H-2 p.1

Recap Schedules: H-1 p.5

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Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study (summary).

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	SUMMARY														
1	RB	$ 742,412,954	$ 265,650,425	$ 168,557	$ 137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -
2	ATTRITION	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	O&M	$ 46,623,423	$ 27,879,012	$ 17,532	$ 6,338,590	$ 5,010,123	$ 1,106,276	$ 5,274,629	$ 889,851	$ -	$ -	$ 107,411	$ -	$ -	$ -
4	DEPRECIATION	$ 24,294,467	$ 8,460,532	$ 5,370	$ 4,567,151	$ 4,395,562	$ 1,013,940	$ 5,111,038	$ 678,047	$ -	$ -	$ 62,826	$ -	$ -	$ -
5	AMORTIZATION EXPENSES	$ 22,157	$ 3,467	$ 0	$ 4,024	$ 4,594	$ 1,109	$ 6,105	$ 2,854	$ -	$ -	$ 3	$ -	$ -	$ -
6	TAXES OTHER THAN INCOME - OTHER	$ 12,104,772	$ 4,252,534	$ 2,669	$ 2,254,984	$ 2,173,721	$ 501,866	$ 2,537,125	$ 351,617	$ -	$ -	$ 30,257	$ -	$ -	$ -
7	TAXES OTHER THAN INCOME - REV. RELATED	$ (1,914,508)	$ (685,050)	$ (435)	$ (355,612)	$ (340,455)	$ (78,452)	$ (394,893)	$ (54,686)	$ -	$ -	$ (4,926)	$ -	$ -	$ -
8	INCOME TAXES TOTAL	$ 14,232,356	$ 5,092,626	$ 3,231	$ 2,643,604	$ 2,530,922	$ 583,207	$ 2,935,615	$ 406,531	$ -	$ -	$ 36,620	$ -	$ -	$ -
9	REVENUE CREDITED TO COS:	$ (2,287,122)	$ (1,710,939)	$ (769)	$ (321,403)	$ (119,982)	$ (25,192)	$ (106,878)	$ -	$ -	$ -	$ (1,960)	$ -	$ -	$ -
10	TOTAL COST - CUSTOMER	$ 66,571,348	$ 48,613,335	$ 40,010	$ 9,339,009	$ 5,080,426	$ 914,333	$ 1,990,345	$ 225,674	$ -	$ -	$ 368,216	$ -	$ -	$ -
11	TOTAL COST - CAPACITY	$ 88,708,768	$ 16,113,425	$ 2,031	$ 17,529,020	$ 19,885,573	$ 4,794,962	$ 26,492,613	$ 3,865,460	$ -	$ -	$ 25,684	$ -	$ -	$ -
12	TOTAL COST - COMMODITY	$ 1,404,455	$ 1,326,023	$ -	$ 78,432	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	TOTAL COST - REVENUE	$ (1,914,508)	$ (685,050)	$ (435)	$ (355,612)	$ (340,455)	$ (78,452)	$ (394,893)	$ (54,686)	$ -	$ -	$ (4,926)	$ -	$ -	$ -
14	NO. OF CUSTOMERS	129,963	120,773	77	7,144	1,620	103	103	9	-	-	134	-	-	-
15	PEAK MONTH SALES	12,083,903	2,092,356	115	2,172,844	2,502,980	605,954	3,253,917	1,453,817	-	-	1,921	-	-	-
16	ANNUAL SALES	127,173,088	17,783,310	1,827	23,326,615	26,392,437	6,357,270	35,834,584	17,457,355	-	-	19,691	-	-	-

Supporting Schedules: H-2 p.2-5

Recap Schedules: H-1 p.6

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Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Allocation of Cost of Service to Customer Classes
Schedule E 2 of 2

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES	Allocation Factor
	TAXES OTHER THAN INCOME TAXES:															
1	Customer	$ 4,142,463	$ 2,791,625	$ 2,471	$ 681,013	$ 390,548	$ 72,033	$ 159,848	$ 17,150	$ -	$ -	$ 27,775	$ -	$ -	$ -	RATEBASE_CUST
2	Capacity	7,962,309	1,460,909	197	1,573,971	1,783,173	429,833	2,377,276	334,467	-	-	2,483	-	-	-	RATEBASE_CAP
3	Subtotal	$ 12,104,772	$ 4,252,534	$ 2,669	$ 2,254,984	$ 2,173,721	$ 501,866	$ 2,537,125	$ 351,617	$ -	$ -	$ 30,257	$ -	$ -	$ -	
4	Revenue	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-	RATE_BASE
5	Total	$ 10,190,264	$ 3,567,484	$ 2,234	$ 1,899,372	$ 1,833,266	$ 423,414	$ 2,142,232	$ 296,931	$ -	$ -	$ 25,331	$ -	$ -	$ -	
	RETURN (NOI)															
6	Customer	$ 21,824,653	$ 14,707,734	$ 13,020	$ 3,587,928	$ 2,057,610	$ 379,508	$ 842,164	$ 90,355	$ -	$ -	$ 146,333	$ -	$ -	$ -	RATEBASE_CUST
7	Capacity	39,800,752	7,302,564	987	7,867,723	8,913,448	2,148,581	11,883,159	1,671,879	-	-	12,410	-	-	-	RATEBASE_CAP
8	Commodity	69,112	65,252	-	3,860	-	-	-	-	-	-	-	-	-	-	RATEBASE_COM
9	Total	$ 61,694,517	$ 22,075,550	$ 14,007	$ 11,459,511	$ 10,971,059	$ 2,528,089	$ 12,725,324	$ 1,762,235	$ -	$ -	$ 158,742	$ -	$ -	$ -	
	INCOME TAXES															
10	Customer	$ 5,034,746	$ 3,392,939	$ 3,004	$ 827,702	$ 474,672	$ 87,549	$ 194,280	$ 20,844	$ -	$ -	$ 33,758	$ -	$ -	$ -	RATEBASE_CUST
11	Capacity	9,181,666	1,684,634	228	1,815,011	2,056,250	495,658	2,741,335	385,687	-	-	2,863	-	-	-	RATEBASE_CAP
12	Commodity	15,943	15,053	-	890	-	-	-	-	-	-	-	-	-	-	RATEBASE_COM
13	Total	$ 14,232,356	$ 5,092,626	$ 3,231	$ 2,643,604	$ 2,530,922	$ 583,207	$ 2,935,615	$ 406,531	$ -	$ -	$ 36,620	$ -	$ -	$ -	
	REVENUE CREDITED TO COS:															
14	Customer	(2,287,122)	(1,710,939)	(769)	(321,403)	(119,982)	(25,192)	(106,878)	-	-	-	(1,960)	-	-	-	OTH_REV
	TOTAL COST OF SERVICE:															
15	Customer	$ 66,571,348	$ 48,613,335	$ 40,010	$ 9,339,009	$ 5,080,426	$ 914,333	$ 1,990,345	$ 225,674	$ -	$ -	$ 368,216	$ -	$ -	$ -	
16	Capacity	88,708,768	16,113,425	2,031	17,529,020	19,885,573	4,794,962	26,492,613	3,865,460	-	-	25,684	-	-	-	
17	Commodity	1,404,455	1,326,023	-	78,432	-	-	-	-	-	-	-	-	-	-	
18	Subtotal	$ 156,684,570	$ 66,052,782	$ 42,041	$ 26,946,461	$ 24,965,999	$ 5,709,295	$ 28,482,957	$ 4,091,135	$ -	$ -	$ 393,900	$ -	$ -	$ -	
19	Revenue	(1,914,508)	(685,050)	(435)	(355,612)	(340,455)	(78,452)	(394,893)	(54,686)	-	-	(4,926)	-	-	-	
20	Total	$ 154,770,062	$ 65,367,732	$ 41,606	$ 26,590,849	$ 24,625,544	$ 5,630,843	$ 28,088,064	$ 4,036,449	$ -	$ -	$ 388,974	$ -	$ -	$ -	

Supporting Schedules: H-2 p.5, H-2 p.6

Recap Schedules: H-2 p.1

Schedule H-2 | Cost of Service | Page 3 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Allocation of Cost of Service to Customer Classes
Schedule E 1 of 2

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES	Allocation Factor
	OPERATIONS AND MAINTENANCE EXPENSE:															
	DIRECT AND SPECIAL ASSIGNMENTS:															
	Customer															
1	870 Operation Supervision & Eng.	$ 265,493	$ 176,169	$ 159	$ 44,810	$ 25,936	$ 4,797	$ 10,637	$ 1,141	$ -	$ -	$ 1,844	$ -	$ -	$ -	PLT_CUST
2	874 Mains and Services	1,495,625	928,475	1,053	269,677	188,276	32,657	55,693	5,408	-	-	14,386	-	-	-	MAINS_SERV_CUST
3	878 Meter and House Reg.	2,208,729	1,601,883	979	336,023	125,811	27,919	97,621	11,676	-	-	6,818	-	-	-	MTRS
4	879 Customer Instal.	77,908	50,197	52	13,614	8,932	1,519	2,666	265	-	-	664	-	-	-	CUST_WTD
5	880 Other Expenses	71,259	45,913	47	12,452	8,170	1,389	2,438	242	-	-	608	-	-	-	CUST_WTD
6	887 Maintenance of Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	MAINS_CUST
7	892 Maintenance of Services	1,029,502	639,108	725	185,630	129,598	22,479	38,336	3,722	-	-	9,903	-	-	-	SERV
8	893 Maint. of Meters and House Reg.	670,568	486,330	297	102,016	38,196	8,476	29,638	3,545	-	-	2,070	-	-	-	MTRS
9	894 Maint. of Other Equipment	41,373	26,657	27	7,229	4,743	807	1,416	141	-	-	353	-	-	-	CUST_WTD
10	901 Supervision	(1,622)	(1,045)	(1)	(283)	(186)	(32)	(55)	(6)	-	-	(14)	-	-	-	CUST_WTD
11	902 Meter-Reading Expense	483,069	448,911	287	26,552	6,023	383	383	32	-	-	497	-	-	-	CUST
12	903 Records and Collection Exp.	6,517,319	6,056,476	3,878	358,230	81,258	5,168	5,165	433	-	-	6,710	-	-	-	CUST
13	(911-916) SALES EXPENSE	166,108	154,363	99	9,130	2,071	132	132	11	-	-	171	-	-	-	CUST
14	(932) MAINT. OF GEN. PLANT	419,118	270,042	278	73,236	48,053	8,171	14,341	1,424	-	-	3,573	-	-	-	CUST_WTD
15	(920-931) ADMINISTRATION AND GENERAL	16,098,169	13,031,705	9,437	1,722,218	798,513	136,340	309,415	33,567	-	-	56,975	-	-	-	O&M_Excl A&G_CUST
16	Total	$ 29,542,619	$ 23,915,185	$ 17,317	$ 3,160,536	$ 1,465,395	$ 250,204	$ 567,823	$ 61,600	$ -	$ -	$ 104,558	$ -	$ -	$ -	
	Capacity															
17	LOCAL STORAGE PLANT	$ 744,740	$ 128,953	$ 7	$ 133,914	$ 154,261	$ 37,345	$ 200,541	$ 89,600	$ -	$ -	$ 118	$ -	$ -	$ -	PMONTH
18	870 Operation Supervision & Eng.	333,199	61,378	8	65,969	74,715	18,009	99,622	13,393	-	-	106	-	-	-	PLT_CAP
19	871 Dist.Load Dispatch	569,041	89,051	7	103,348	117,981	28,490	156,787	73,288	-	-	89	-	-	-	PEAK_AVRG
20	874 Mains and Services	3,515,817	619,250	47	719,484	821,278	198,320	1,091,640	65,176	-	-	621	-	-	-	MAINS_CAP
21	875 Meas.& Reg. Sta.Eq.-Gen	89,643	14,029	1	16,281	18,586	4,488	24,699	11,545	-	-	14	-	-	-	PEAK_AVRG
22	876 Meas.& Reg. Sta.Eq.-Ind.	250,986	39,278	3	45,584	52,038	12,566	69,154	32,325	-	-	39	-	-	-	PEAK_AVRG
23	877 Meas.& Reg. Sta.Eq.-CG	321,336	50,287	4	58,361	66,623	16,088	88,537	41,385	-	-	50	-	-	-	PEAK_AVRG
24	879 Customer Instal.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	PEAK_AVRG
25	880 Other Expenses	121,975	19,088	1	22,153	25,289	6,107	33,607	15,709	-	-	19	-	-	-	PEAK_AVRG
26	881 Rents	109,399	20,152	3	21,659	24,531	5,913	32,709	4,397	-	-	35	-	-	-	PLT_CAP
27	886 Maint. of Struct. and Improv.	4,566	794	0	922	1,052	254	1,419	124	-	-	1	-	-	-	DISTPLT_CAP
28	887 Maintenance of Mains	546,553	96,266	7	111,848	127,672	30,830	169,702	10,132	-	-	97	-	-	-	MAINS_CAP
29	889 Maint. of Meas.& Reg. Sta.Eq.-Gen	37,211	6,554	1	7,615	8,692	2,099	11,554	690	-	-	7	-	-	-	MAINS_CAP
30	891 Maint. of Meas.& Reg.Sta.Eq.-CG	38,403	6,010	0	6,975	7,962	1,923	10,581	4,946	-	-	6	-	-	-	PEAK_AVRG
31	894 Maint. of Other Equipment	70,817	13,045	2	14,021	15,880	3,828	21,173	2,846	-	-	22	-	-	-	PLT_CAP
32	(932) MAINT. OF GEN. PLANT	419,118	72,840	6	84,625	96,598	23,326	130,279	11,370	-	-	73	-	-	-	DISTPLT_CAP
33	(920-931) ADMINISTRATION AND GENERAL	8,588,601	1,481,134	117	1,691,614	1,931,570	466,485	2,564,801	451,325	-	-	1,554	-	-	-	O&M_Excl A&G_CAP
34	Total	$ 15,761,405	$ 2,718,110	$ 214	$ 3,104,372	$ 3,544,729	$ 856,071	$ 4,706,806	$ 828,250	$ -	$ -	$ 2,852	$ -	$ -	$ -	
	Commodity															
35	Account #	$ -	$ -	$ -	$ -	$ -	$ -									
36	Account #	-	-	-	-	-	-									
37	Account #	-	-	-	-	-	-									
38	904 Uncollectible Accounts	600,441	566,909	-	33,532	-	-	-	-	-	-	-	-	-	-	CUST_RES & GS-1
39	(920-931) ADMINISTRATION AND GENERAL	718,958	678,808	-	40,150	-	-	-	-	-	-	-	-	-	-	CUST_RES & GS-1
40	Total	$ 1,319,399	$ 1,245,717	$ -	$ 73,682	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
41	TOTAL O&M	$ 46,623,423	$ 27,879,012	$ 17,532	$ 6,338,590	$ 5,010,123	$ 1,106,276	$ 5,274,629	$ 889,851	$ -	$ -	$ 107,411	$ -	$ -	$ -	
	DEPRECIATION EXPENSE:															
42	Customer	$ 8,313,989	$ 5,516,792	$ 4,966	$ 1,403,233	$ 812,183	$ 150,231	$ 333,107	$ 35,724	$ -	$ -	$ 57,753	$ -	$ -	$ -	PLT_CUST
43	Capacity	15,980,479	2,943,740	404	3,163,918	3,583,379	863,710	4,777,932	642,323	-	-	5,073	-	-	-	PLT_CAP
44	Total	$ 24,294,467	$ 8,460,532	$ 5,370	$ 4,567,151	$ 4,395,562	$ 1,013,940	$ 5,111,038	$ 678,047	$ -	$ -	$ 62,826	$ -	$ -	$ -	
	AMORT. OF GAS PLANT:															
45	Capacity	$ 424,854	$ 66,487	$ 5	$ 77,161	$ 88,086	$ 21,271	$ 117,059	$ 54,717	$ -	$ -	$ 67	$ -	$ -	$ -	PEAK_AVRG
	AMORT. OF PROPERTY LOSS:															
46	Capacity	$ 721,895	$ 112,972	$ 9	$ 131,109	$ 149,672	$ 36,143	$ 198,902	$ 92,974	$ -	$ -	$ 113	$ -	$ -	$ -	PEAK_AVRG
	AMORT OF LIMITED TERM INVEST.															
47	Capacity	$ (1,124,591)	$ (175,992)	$ (13)	$ (204,247)	$ (233,164)	$ (56,305)	$ (309,856)	$ (144,838)	$ -	$ -	$ (176)	$ -	$ -	$ -	PEAK_AVRG
	AMORT. OF ACQUISITION ADJ.:															
48	Customer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CUST_WTD
49	Capacity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	PEAK_AVRG
50	Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
	AMORT. OF CONVERSION COSTS:															
51	Commodity	-	-	-	-	-	-	-	-	-	-	-	-	-	-	

Supportin Supporting Schedules: H-2 p.5, H-2 p.6 | Recap Schedules: H-2 p.1

Schedule H-2 | Cost of Service | Page 4 of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Allocation of Rate Base to Customer Classes
Schedule F

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES	Allocation Factor
	DIRECT AND SPECIAL ASSIGNMENTS:															
	Customer															
1	380 Services	$ 119,242,428	$ 74,024,984	$ 83,941	$ 21,500,708	$ 15,010,781	$ 2,603,640	$ 4,440,262	$ 431,149	$ -	$ -	$ 1,146,962	$ -	$ -	$ -	SERV
2	381-382 Meters	72,991,954	52,937,475	32,361	11,104,569	4,157,666	922,641	3,226,074	385,852	-	-	225,317	-	-	-	MTRS
3	383-384 House Regulators	9,943,119	7,211,256	4,408	1,512,688	566,366	125,684	439,463	52,562	-	-	30,693	-	-	-	MTRS
4	376 Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CUST_Excl GS-5
5	376 Mains - Direct Assigment	-							-							Direct Assign
6	386 Property on Customer Premises	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CUST_WTD
7	387 Other Equipment	922,310	594,254	613	161,163	105,746	17,981	31,558	3,133	-	-	7,863	-	-	-	CUST_WTD
8	General Plant	15,005,163	9,956,757	8,963	2,532,567	1,465,835	271,138	601,194	64,475	-	-	104,234	-	-	-	DISTPLT_CUST
9	Working Capital	18,621,871	15,074,678	10,916	1,992,210	923,696	157,714	357,921	38,829	-	-	65,907	-	-	-	O&M_CUST
10	Plant Acquisitions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	CUST_WTD
11	General Common Plant	15,030,789	9,973,761	8,979	2,536,892	1,468,338	271,601	602,221	64,586	-	-	104,412	-	-	-	DISTPLT_CUST
12	Retirement Work In Progress:	260,563	172,898	156	43,978	25,454	4,708	10,440	1,120	-	-	1,810	-	-	-	PLT_CUST
13	CWIP	10,613,002	7,042,314	6,340	1,791,259	1,036,770	191,773	425,218	45,603	-	-	73,723	-	-	-	PLT_CUST
14	Total	$ 262,631,199	$ 176,988,376	$ 156,677	$ 43,176,034	$ 24,760,652	$ 4,566,880	$ 10,134,350	$ 1,087,308	$ -	$ -	$ 1,760,921	$ -	$ -	$ -	
	Capacity															
15	Local Storage Plant	$ 64,287,485	$ 11,131,526	$ 612	$ 11,559,732	$ 13,316,084	$ 3,223,730	$ 17,311,141	$ 7,734,442	$ -	$ -	$ 10,219	$ -	$ -	$ -	PMONTH
16	Intangible Plant	24,559,516	8,911,701	5,864	4,644,741	4,401,495	1,010,528	5,066,913	449,786	-	-	68,489	-	-	-	DISTPLT_SUBTOTAL
17	385 Industrial Meas.& Reg.Eq.	2,099,077	-	-	-	-	-	1,450,852	648,226	-	-	-	-	-	-	M&R
18	378 Meas. & Reg. Sta. Eq.-Gen	9,567,563	1,497,265	114	1,737,648	1,983,667	479,022	2,636,127	1,232,219	-	-	1,501	-	-	-	PEAK_AVRG
19	379 Meas. & Reg. Sta. Eq.-CG	8,613,967	1,348,033	103	1,564,457	1,785,955	431,278	2,373,385	1,109,404	-	-	1,351	-	-	-	PEAK_AVRG
20	376 Mains	295,687,743	53,063,928	4,061	61,653,066	70,375,862	16,994,173	93,543,404	-	-	-	53,248	-	-	-	PEAK_AVRG_Excl GS-5
21	376 Mains - Direct Assigment	5,584,971							5,584,971							Direct Assign
22	386 Property on Customer Premises	-	-	-	-	-	-	-	-	-	-	-	-	-	-	PEAK_AVRG
23	387 Other Equipment	1,457,695	228,120	17	264,744	302,227	72,983	401,635	187,738	-	-	229	-	-	-	PEAK_AVRG
24	General Plant	15,005,163	2,607,806	200	3,029,728	3,458,396	835,125	4,664,236	407,056	-	-	2,617	-	-	-	DISTPLT_CAP
25	Working Capital	9,935,031	1,713,331	135	1,956,807	2,234,381	539,615	2,966,884	522,079	-	-	1,798	-	-	-	O&M_CAP
26	Plant Acquisitions	5,293,892	828,462	63	961,469	1,097,596	265,051	1,458,613	681,807	-	-	831	-	-	-	PEAK_AVRG
27	General Common Plant	15,030,789	2,612,260	200	3,034,902	3,464,302	836,552	4,672,201	407,751	-	-	2,621	-	-	-	DISTPLT_CAP
28	Retirement Work In Progress:	448,374	82,594	11	88,772	100,541	24,234	134,057	18,022	-	-	142	-	-	-	PLT_CAP
29	CWIP	18,262,706	3,364,146	462	3,615,768	4,095,134	987,059	5,460,284	734,056	-	-	5,797	-	-	-	PLT_CAP
30	All Other	3,116,114	487,653	37	565,944	646,072	156,015	858,575	401,328	-	-	489	-	-	-	PEAK_AVRG
31	Total	$ 478,950,086	$ 87,876,825	$ 11,880	$ 94,677,779	$ 107,261,712	$ 25,855,366	$ 142,998,307	$ 20,118,886	$ -	$ -	$ 149,333	$ -	$ -	$ -	
	Commodity															
32	Account #	-	-	-	-	-	-									
33	Account #	-	-	-	-	-	-									
34	Account #	-	-	-	-	-	-									
35	Working Capital	$ 831,669	$ 785,224	$ -	$ 46,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	CUST_RES & GS-1
36	Total	$ 831,669	$ 785,224	$ -	$ 46,445	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
37	TOTAL	$ 742,412,954	$ 265,650,425	$ 168,557	$ 137,900,257	$ 132,022,365	$ 30,422,246	$ 153,132,657	$ 21,206,194	$ -	$ -	$ 1,910,254	$ -	$ -	$ -	

Supporting Schedules: H-2 p.5, H-2 p.6 | Recap Schedules: H-2 p.1

Schedule H-2 | Cost of Service | Page 5a of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2030
Witness: J. Taylor

Development of Allocation Factors
Schedule G

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Gas Lighting GL	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	CUSTOMER ALLOCATORS															
1	**CUST_WTD**	**100.0%**	**64.4%**	**0.1%**	**17.5%**	**11.5%**	**1.9%**	**3.4%**	**0.3%**	**0.0%**	**0.0%**	**0.0%**	**0.9%**	**0.0%**	**0.0%**	**0.0%**
	No. of Customers	129,963	120,773	77	7,144	1,620	103	103	9	-	-	-	134			
	Weighting		1.00	1.61	4.59	13.26	35.46	62.27	73.73	-	-	-	11.94	-	-	-
	Weighted No. of Customers	187,446	120,773	125	32,754	21,491	3,654	6,414	637	-	-	-	1,598	-	-	-
2	**CUST_WTD_Excl GS-5**	**100.0%**	**64.7%**	**0.1%**	**17.5%**	**11.5%**	**2.0%**	**3.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.9%**	**0.0%**	**0.0%**	**0.0%**
	No. of Customers	129,954	120,773	77	7,144	1,620	103	103		-	-	-	134		-	-
	Weighting		1.00	1.61	4.59	13.26	35.46	62.27	73.73	-	-	-	11.94	-	-	-
	Weighted No. of Customers	186,809	120,773	125	32,754	21,491	3,654	6,414	-	-	-	-	1,598	-	-	-
3	**CUST**	**100.0%**	**92.9%**	**0.1%**	**5.5%**	**1.2%**	**0.1%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**
	Average Number Customers - TY 2027	129,963	120,773	77	7,144	1,620	103	103	9	-	-	-	134			-
4	**CUST_Excl GS-5**	**100.0%**	**92.9%**	**0.1%**	**5.5%**	**1.2%**	**0.1%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.1%**	**0.0%**	**0.0%**	**0.0%**
	Average Number Customers - TY 2027	129,954	120,773	77	7,144	1,620	103	103		-	-	-	134		-	-
5	**CUST_RES & GS-1**	**100.0%**	**94.4%**	**0.0%**	**5.6%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
	Average Number Customers - TY 2027	127,917	120,773		7,144											
6	**MTRS**	**100.0%**	**72.5%**	**0.0%**	**15.2%**	**5.7%**	**1.3%**	**4.4%**	**0.5%**	**0.0%**	**0.0%**	**0.0%**	**0.3%**	**0.0%**	**0.0%**	**0.0%**
	Meter Cost Per Meter		$ 169.33	$ 161.66	$ 600.53	$ 991.24	$ 3,458.95	$ 12,099.43	$ 17,258.46	$ -	$ -	$ -	$ 650.52	$ -	$ -	$ -
	Relative Weighting Factor		$ 1.05	$ 1.00	$ 3.71	$ 6.13	$ 21.40	$ 74.85	$ 106.76	$ -	$ -	$ -	$ 4.02	$ -	$ -	$ -
	Weighted Customers	174,429	126,505	77	26,537	9,936	2,205	7,709	922	-	-	-	538	-	-	-
7	**SERV**		**62.08%**	**0.07%**	**18.03%**	**12.59%**	**2.18%**	**3.72%**	**0.36%**	**0.00%**	**0.00%**	**0.00%**	**0.96%**	**0.00%**	**0.00%**	**0.00%**
	Service Cost per Service		$ 2,928.56	$ 5,186.27	$ 14,380.90	$ 44,262.34	$ 120,724.36	$ 205,968.95	$ 238,512.52	$ -	$ -	$ -	$ 40,955.97	$ -	$ -	$ -
	Relative Weighting Factor		$ 18.12	$ 32.08	$ 88.96	$ 273.80	$ 746.78	$ 1,274.09	$ 1,475.40	$ -	$ -	$ -	$ 253.35	$ -	$ -	$ -
	Weighted Customers	3,524,329	2,187,882	2,481	635,475	443,659	76,953	131,236	12,743	-	-	-	33,900	-	-	-
8	**M&R**	100%	0.00%	0.00%	0.00%	0.00%	0.00%	69.12%	30.88%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	Industrial Measuring and Regulating	4,707,734						3,253,917	1,453,817	-	-					
	DEMAND ALLOCATORS															
9	**PMONTH**	100%	17.3%	0.0%	18.0%	20.7%	5.0%	26.9%	12.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	January Sales Volumes	12,083,903	2,092,356	115	2,172,844	2,502,980	605,954	3,253,917	1,453,817	0	0	0	1,921			
10	**PMONTH_Excl GS-5**	100%	19.7%	0.0%	20.4%	23.5%	5.7%	30.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	January Sales Volumes	10,630,086	2,092,356	115	2,172,844	2,502,980	605,954	3,253,917		0	0	0	1,921		0	0
11	**PEAK_AVRG**	100%	15.6%	0.0%	18.2%	20.7%	5.0%	27.6%	12.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	**PEAK_AVRG_Excl GS-5**	100%	17.9%	0.0%	20.9%	23.8%	5.7%	31.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Supporting Schedules: E-2 p.3, E-4 p.1, H-2 p.6

Recap Schedules: H-2 p.2-4

Schedule H-2 | Cost of Service | Page 5b of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2030
Witness: J. Taylor

Development of Allocation Factors
Schedule G

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Gas Lighting GL	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
	COMMODITY ALLOCATORS															
13	**COM**	100%	14%	0%	18%	21%	5%	28%	14%	0%	0%	0%	0%	0%	0%	0%
	Annual Sales Vol.(therms)	127,173,088	17,783,310	1,827	23,326,615	26,392,437	6,357,270	35,834,584	17,457,355	-	-	-	19,691			
14	**COM_Excl GS-5**	100%	16%	0%	21%	24%	6%	33%	0%	0%	0%	0%	0%	0%	0%	0%
	Annual Sales Vol.(therms)	109,715,732	17,783,310	1,827	23,326,615	26,392,437	6,357,270	35,834,584		-	-	-	19,691		-	-
15	**COM_RES & GS-1**	100%	43%	0%	57%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	Annual Sales Vol.(therms)	41,111,752	17,783,310	1,827	23,326,615											
	REVENUE-RELATED COSTS															
16	**MISC_REV_NSF**	100%	83.1%	0.0%	9.6%	5.0%	0.4%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	2025 NFS Fees	25,975	21,582	-	2,497	1,298	112	487	-	-	-	-	-	-	-	-
17	**MISC_REV_Late Payment**	100%	77.0%	0.0%	9.3%	6.2%	1.4%	6.1%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
	2025 Late Payment Fees	1,530,328	1,178,001	589	141,692	94,673	20,693	93,267	-	-	-	-	1,413	-	-	-
18	**MISC_REV**	100%	79.5%	0.0%	9.5%	5.4%	1.1%	4.3%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
	2025 Various Fees	1,970,735	1,566,390	760	188,025	106,491	22,269	84,643	-	-	-	-	2,158	-	-	-
19	**OTH_REV**	100%	74.8%	0.0%	14.1%	5.2%	1.1%	4.7%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
	Total Other Revenue	$2,287,122	$1,710,939	$769	$321,403	$119,982	$25,192	$106,878	$0	$0	$0	$0	$1,960	$0	$0	$0
	Water Heater Interest	$225,320	$97,464	$10	$127,845	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Late Payment Charges	$1,142,643	$879,572	$440	$105,797	$70,689	$15,451	$69,639	$0	$0	$0	$0	$1,055	$0	$0	$0
	Miscellaneous Service Revenue	$826,685	$657,070	$319	$78,873	$44,671	$9,341	$35,506	$0	$0	$0	$0	$905	$0	$0	$0
	NSF Charges	$92,475	$76,833	$0	$8,888	$4,622	$400	$1,733	$0	$0	$0	$0	$0	$0	$0	$0
	KDS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	TPS		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	LES		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**REV_ADJ**	100%	41.39%	0.03%	16.91%	15.12%	3.31%	14.00%	3.99%	0.00%	0.00%	0.00%	0.06%	3.55%	0.31%	1.33%
	Revenue Excluding Adjustments	$ 91,496,185	$ 37,874,673	$ 23,200	$ 15,471,170	$ 13,829,899	$ 3,032,595	$ 12,813,395	$ 3,653,286	$ -	$ -	$ -	$ 57,804	$ 3,246,230	$ 280,181	$ 1,213,751
21	**REV**	100%	41%	0%	22%	17%	3%	11%	3%	0%	0%	0%	0%	2%	0%	1%
	Total Revenues	157,052,757	63,753,272	26,028	34,543,358	27,309,401	5,071,567	17,417,088	4,108,399	-	-	-	83,482	3,246,230	280,181	1,213,751
	INTERNAL ALLOCATOR															
22	**RATE_BASE**	100.0%	35.8%	0.0%	18.6%	17.8%	4.1%	20.6%	2.9%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
	Rate Base	742,412,954	265,650,425	168,557	137,900,257	132,022,365	30,422,246	153,132,657	21,206,194	-	-	-	1,910,254	-	-	-
23	**O&M_CUST**	100.0%	81.0%	0.1%	10.7%	5.0%	0.8%	1.9%	0.2%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%
	O&M_Customer	29,542,619	23,915,185	17,317	3,160,536	1,465,395	250,204	567,823	61,600	-	-	-	104,558	-	-	-
24	**O&M_CAP**	100.0%	17.2%	0.0%	19.7%	22.5%	5.4%	29.9%	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	O&M_Capacity	15,761,405	2,718,110	214	3,104,372	3,544,729	856,071	4,706,806	828,250	-	-	-	2,852	-	-	-
25	**O&M_Excl A&G_CUST**	100.0%	81.0%	0.1%	10.7%	5.0%	0.8%	1.9%	0.2%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%	0.0%
	O&M Excluding A&G_Customer	13,444,450	10,883,480	7,881	1,438,317	666,882	113,865	258,409	28,034	-	-	-	47,583	-	-	-
26	**O&M_Excl A&G_CAP**	100.0%	17.2%	0.0%	19.7%	22.5%	5.4%	29.9%	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	O&M Excluding A&G_Capacity	7,172,804	1,236,975	98	1,412,758	1,613,158	389,587	2,142,004	376,926	-	-	-	1,298	-	-	-
27	**MAINS_SERV_CUST**	100%	62.1%	0.1%	18.0%	12.6%	2.2%	3.7%	0.4%	0.0%	0.0%	0.0%	1.0%	0.0%	0.0%	0.0%
	Total Mains and Services (Cust)	119,242,428	74,024,984	83,941	21,500,708	15,010,781	2,603,640	4,440,262	431,149	-	-	-	1,146,962	-	-	-
28	**MAINS_CUST**	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
	Total Mains (Cust)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Supporting Schedules: E-2 p.3, E-4 p.1, H-2 p.6

Recap Schedules: H-2 p.2-4

Schedule H-2 | Cost of Service | Page 5c of 6

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2030
Witness: J. Taylor

Development of Allocation Factors
Schedule G

Line No.		Total	Residential Service RS	Residential Standby Generator RSG	General Service 1 GS - 1	General Service 2 GS - 2 (10K)	General Service 3 GS - 3 (50K)	General Service 4 GS - 4 (120K)	General Service 5 GS - 5 (1250K)	General Service 6 GS - 6 (11M)	General Service 7 GS - 7 (25M)	Gas Lighting GL	Commercial Standby Generator CSG	Contract Demand KDS	Third Party Supplier TPS	Load Enhancement Service LES
29	**MAINS_CAP**	100%	17.6%	0.0%	20.5%	23.4%	5.6%	31.0%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Mains (Capacity)	301,272,714	53,063,928	4,061	61,653,066	70,375,862	16,994,173	93,543,404	5,584,971	-	-	-	53,248	-	-	-
30	**PLT_CUST**	100.0%	66.4%	0.1%	16.9%	9.8%	1.8%	4.0%	0.4%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
	Total Plant (Customer)	233,135,763	154,698,485	139,266	39,348,587	22,774,732	4,212,685	9,340,771	1,001,757	-	-	-	1,619,481	-	-	-
31	**PLT_CAP**	100.0%	18.4%	0.0%	19.8%	22.4%	5.4%	29.9%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Plant (Capacity)	441,893,969	81,400,639	11,171	87,489,017	99,087,989	23,883,391	132,119,893	17,761,594	-	-	-	140,275	-	-	-
32	**DISTPLT_SUBTOTAL**	100.0%	36.3%	0.0%	18.9%	17.9%	4.1%	20.6%	1.8%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
	Total Dist Plant (Excl Intangible)	526,110,827	190,905,315	125,619	99,499,043	94,288,270	21,647,402	108,542,759	9,635,254	-	-	-	1,467,165	-	-	-
33	**DISTPLT_CUST**	100.0%	66.4%	0.1%	16.9%	9.8%	1.8%	4.0%	0.4%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
	Total Plant (Customer)	203,099,811	134,767,968	121,323	34,279,128	19,840,559	3,669,945	8,137,356	872,696	-	-	-	1,410,836	-	-	-
34	**DISTPLT_CAP**	100.0%	17.4%	0.0%	20.2%	23.0%	5.6%	31.1%	2.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Total Plant (Capacity)	323,011,016	56,137,347	4,296	65,219,915	74,447,711	17,977,456	100,405,402	8,762,558	-	-	-	56,330	-	-	-
35	**RATEBASE_CUST**	100.0%	67.4%	0.1%	16.4%	9.4%	1.7%	3.9%	0.4%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%
	Rate Base (Customer)	262,631,199	176,988,376	156,677	43,176,034	24,760,652	4,566,880	10,134,350	1,087,308	-	-	-	1,760,921	-	-	-
36	**RATEBASE_CAP**	100.0%	18.3%	0.0%	19.8%	22.4%	5.4%	29.9%	4.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Rate Base (Capacity)	478,950,086	87,876,825	11,880	94,677,779	107,261,712	25,855,366	142,998,307	20,118,886	-	-	-	149,333	-	-	-
37	**RATEBASE_COM**	100.0%	94.4%	0.0%	5.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
	Rate Base (Commodity)	831,669	785,224	-	46,445	-	-	-	-	-	-	-	-	-	-	-
37	**REV_REQ_PRETAX**	100.0%	42.2%	0.0%	17.2%	15.9%	3.6%	18.2%	2.6%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
	Revenue Requirement (Total)	156,684,570	66,052,782	42,041	26,946,461	24,965,999	5,709,295	28,482,957	4,091,135	-	-	-	393,900	-	-	-
38	**REV_REQ**	100.0%	42.7%	0.0%	17.1%	15.8%	3.6%	18.0%	2.6%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%
	Revenue Requirement (Total)	157,057,184	67,078,672	42,375	26,912,251	24,745,526	5,656,035	28,194,942	4,036,449	-	-	-	390,934	-	-	-

Supporting Schedules: E-2 p.3, E-4 p.1, H-2 p.6

Recap Schedules: H-2 p.2-4

Schedule H-2 | Cost of Service | Page 6 of 6

Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Fully allocated embedded cost of service study (summary).

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Line No.	Summary:	Total	Customer	Capacity	Commodity	Revenue
	ATTRITION	$ -	$ -	$ -	$ -	$ -
1	O&M	$ 46,623,423	$ 29,542,619	$ 15,761,405	$ 1,319,399	$ -
2	DEP.	$ 24,294,467	$ 8,313,989	$ 15,980,479	$ -	$ -
3	AMORTIZATION OF OTHER GAS PLANT	$ 424,854	$ -	$ 424,854	$ -	$ -
4	AMORTIZATION OF PROPERTY LOSS	$ 721,895	$ -	$ 721,895	$ -	$ -
5	AMORTIZATION OF LIMITED TERM INVESTMENT	$ (1,124,591)	$ -	$ (1,124,591)	$ -	$ -
6	AMORTIZATION OF ACQUISITION ADJUSTMENT	$ -	$ -	$ -	$ -	$ -
7	AMORTIZATION OF CONVERSION COSTS	$ -	$ -	$ -	$ -	$ -
8	TAXES OTHER THAN INCOME TAXES	$ 10,190,264	$ 4,142,463	$ 7,962,309	$ -	$ (1,914,508)
9	RETURN	$ 61,694,517	$ 21,824,653	$ 39,800,752	$ 69,112	$ -
10	INCOME TAXES	$ 14,232,356	$ 5,034,746	$ 9,181,666	$ 15,943	$ -
11	REVENUE CREDITED TO COST OF SERVICE	$ (2,287,122)	$ (2,287,122)	$ -	$ -	$ -
12	TOTAL COST OF SERVICE	$ 154,770,062	$ 66,571,348	$ 88,708,768	$ 1,404,455	$ (1,914,508)
13	RATE BASE	$ 742,412,954	$ 262,631,199	$ 478,950,086	$ 831,669	$ -
	KNOWN DIRECT & SPECIAL ASSIGNMENTS: RATE BASE ITEMS(PLANT-ACC.DEP):					
14	381-382 METERS	$ 72,991,954	$ 72,991,954	$ -	$ -	$ -
15	383-384 HOUSE REGULATORS	$ 9,943,119	$ 9,943,119	$ -	$ -	$ -
16	385 INDUSTRIAL MEAS.& REG.EQ.	$ 2,099,077	$ -	$ 2,099,077	$ -	$ -
17	376 MAINS	$ 301,272,714	$ -	$ 301,272,714	$ -	$ -
18	380 SERVICES	$ 119,242,428	$ 119,242,428	$ -	$ -	$ -
19	378 MEAS.& REG.STA.EQ.-GEN.	$ 9,567,563	$ -	$ 9,567,563	$ -	$ -
20	367 Transmission Mains	$ -	$ -	$ -	$ -	$ -
21	892 Maint. of Services O & M ITEMS	$ 1,029,502	$ 1,029,502	$ -	$ -	$ -
22	876 MEAS.& REG.STA.EQ.IND.	$ 250,986	$ -	$ 250,986	$ -	$ -
23	878 METER & HOUSE REG.	$ 2,208,729	$ 2,208,729	$ -	$ -	$ -
24	890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	$ -	$ -	$ -	$ -	$ -
25	893 MAINT.OF METERS AND HOUSE REG.	$ 670,568	$ 670,568	$ -	$ -	$ -
26	874 MAINS AND SERVICES	$ 5,011,442	$ 1,495,625	$ 3,515,817	$ -	$ -
27	887 MAINT. OF MAINS	$ 546,553	$ -	$ 546,553	$ -	$ -

Supporting Schedules: H-3 p.1

Recap Schedules: H-2 p.2-4

Schedule H-3 | Cost of Service | Page 1 of 5

Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Provide a fully allocated embedded cost of service study (summary).

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Line No.		Total	Customer	Capacity	Commodity	Revenue
	SUMMARY:					
1	ATTRITION	$ -	$ -	$ -	$ -	$ -
2	O&M	$ 46,623,423	$ 29,542,619	$ 15,761,405	$ 1,319,399	
3	DEP.	$ 24,294,467	$ 8,313,989	$ 15,980,479	$ -	$ -
4	AMORTIZATION OF OTHER GAS PLANT	$ 424,854	$ -	$ 424,854	$ -	$ -
5	AMORTIZATION OF PROPERTY LOSS	$ 721,895	$ -	$ 721,895	$ -	$ -
6	AMORTIZATION OF LIMITED TERM INVESTMENT	$ (1,124,591)	$ -	$ (1,124,591)	$ -	$ -
7	AMORTIZATION OF ACQUISITION ADJUSTMENT	$ -	$ -	$ -	$ -	$ -
8	AMORTIZATION OF CONVERSION COSTS	$ -	$ -	$ -	$ -	$ -
9	TOTAL TAXES OTHER THAN INCOME	$ 10,190,264	$ 4,142,463	$ 7,962,309	$ -	$ (1,914,508)
10	RETURN	$ 61,694,517	$ 21,824,653	$ 39,800,752	$ 69,112	$ -
11	INCOME TAXES	$ 14,232,356	$ 5,034,746	$ 9,181,666	$ 15,943	$ -
12	REVENUES CREDITED TO COST OF SERVICE	$ (2,287,122)	$ (2,287,122)	$ -	$ -	$ -
13	TOTAL COST	$ 154,770,062	$ 66,571,348	$ 88,708,768	$ 1,404,455	$ (1,914,508)
14	RATE BASE	$ 742,412,954	$ 262,631,199	$ 478,950,086	$ 831,669	
	KNOWN DIRECT & SPECICAL ASSIGNMENTS: RATE BASE ITEMS(PLANT-ACC.DEP):					
15	381-382 METERS	$ 72,991,954	$ 72,991,954	$ -	$ -	
16	383-384 HOUSE REGULATORS	$ 9,943,119	$ 9,943,119	$ -	$ -	
17	385 INDUSTRIAL MEAS.& REG.EQ.	$ 2,099,077	$ -	$ 2,099,077	$ -	
18	376 MAINS	$ 301,272,714	$ -	$ 301,272,714	$ -	
19	380 SERVICES	$ 119,242,428	$ 119,242,428	$ -	$ -	
20	378 MEAS.& REG.STA.EQ.-GEN.	$ 9,567,563	$ -	$ 9,567,563	$ -	
21	367 Transmission Mains	$ -	$ -	$ -	$ -	
22	892 Maint. of Services O & M ITEMS	$ 1,029,502	$ 1,029,502			
23	876 MEAS.& REG.STA.EQ.IND.	$ 250,986	$ -	$ 250,986	$ -	
24	878 METER & HOUSE REG.	$ 2,208,729	$ 2,208,729	$ -	$ -	
25	890 MAINT.OF MEAS.& REG.STA.EQ.-IND.	$ -	$ -	$ -	$ -	
26	893 MAINT.OF METERS AND HOUSE REG.	$ 670,568	$ 670,568	$ -	$ -	
27	874 MAINS AND SERVICES	$ 5,011,442	$ 1,495,625	$ 3,515,817	$ -	
28	887 MAINT. OF MAINS	$ 546,553	$ -	$ 546,553	$ -	

Supporting Schedules: H-3 p.2-4

Recap Schedules: H-2, p.6

Schedule H-3 | Cost of Service | Page 2 of 5

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Provide a fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Classification of Expenses and Derivation of Cost of Service by Cost Classification
Schedule H 1 of 2

Line No.	Operation and Maintenance Expenses	Total	Customer	Capacity	Commodity	Classifier
1	LOCAL STORAGE PLANT	$ 744,740	$ -	$ 744,740	$ -	ac 301-320
2	PRODUCTION PLANT	-		-		100% capacity
	DISTRIBUTION:					
3	870 Operation Supervision & Eng.	598,692	265,493	333,199	-	ac 871-879
4	871 Dist.Load Dispatch	569,041		569,041		100% capacity
5	872 Compr.Sta.Lab. & Ex.	-	-	-	-	ac 377
6	873 Compr.Sta.Fuel & Power	-			-	100% commodity
7	874 Mains and Services	5,011,442	1,495,625	3,515,817	-	ac376+ac380
8	875 Meas.& Reg. Sta.Eq.-Gen	89,643	-	89,643	-	ac 378
9	876 Meas.& Reg. Sta.Eq.-Ind.	250,986	-	250,986	-	ac 385
10	877 Meas.& Reg. Sta.Eq.-CG	321,336	-	321,336	-	ac 379
11	878 Meter and House Reg.	2,208,729	2,208,729	-	-	ac381+ac383
12	879 Customer Instal.	77,908	77,908	-	-	100% customer
13	880 Other Expenses	193,234	71,259	121,975	-	ac 387
14	881 Rents	109,399		109,399		100% capacity
15	885 Maintenance Supervision	-	-	-	-	ac886-894
16	886 Maint. of Struct. and Improv.	4,566	-	4,566	-	ac375
17	887 Maintenance of Mains	546,553	-	546,553	-	ac376
18	888 Maint. of Comp.Sta.Eq.	-	-	-	-	ac 377
19	889 Maint. of Meas.& Reg. Sta.Eq.-Gen	37,211	-	37,211	-	ac 378
20	890 Maint. of Meas.& Reg. Sta.Eq.-Ind.	-	-	-	-	ac 385
21	891 Maint. of Meas.& Reg.Sta.Eq.-CG	38,403	-	38,403	-	ac 379
22	892 Maintenance of Services	1,029,502	1,029,502	-	-	ac 380
23	893 Maint. of Meters and House Reg.	670,568	670,568	-	-	ac381-383
24	894 Maint. of Other Equipment	112,190	41,373	70,817	-	ac387
25	Total Distribution Expenses	$ 11,869,404	$ 5,860,457	$ 6,008,946	$ -	
	CUSTOMER ACCOUNTS:					
26	901 Supervision	$ (1,622)	$ (1,622)			100% customer
27	902 Meter-Reading Expense	483,069	483,069			"
28	903 Records and Collection Exp.	6,517,319	6,517,319			"
29	904 Uncollectible Accounts	600,441			600,441	100% commodity
30	905 Misc. Expenses	-	-			100% customer
31	Total Customer Accounts	$ 7,599,208	$ 6,998,767	$ -	$ 600,441	
32	(907-910) CUSTOMER SERV.& INFO. EXP.	$ -	$ -			"
33	(911-916) SALES EXPENSE	166,108	166,108			"
34	(932) MAINT. OF GEN. PLANT	838,235	419,118	419,118	-	general plant
35	(920-931) ADMINISTRATION AND GENERAL	25,405,728	16,098,169	8,588,601	718,958	O&M excl. A&G
36	TOTAL O&M EXPENSE	$ 46,623,423	$ 29,542,619	$ 15,761,405	$ 1,319,399	

Supporting Schedules: G- 2 p.10-19 | Recap Schedules: H-3 p.1

Schedule H-3 | Cost of Service | Page 3 of 5

Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Provide a fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Classification of Expenses and Derivation of Cost of Service by Cost Classification
Schedule H 2 of 2

Line No.	Depreciation and Amortization Expense:	Total	Customer	Capacity	Commodity	Revenue	Classifier
1	Depreciation Expense	$ 24,294,467	$ 8,313,989	$ 15,980,479	$ -		net plant
2	AMORT. OF PIPING AND CONVERSION	424,854		424,854			100% capacity
3	AMORT. OF ACQUISITION ADJ.	721,895		721,895			100% capacity
4	AMORT. RELATED TO 2017 TAX REFORM	(1,124,591)	-	(1,124,591)	-		intangible plant
5	AMORT. OF AEP	-	-	-	-		intangible,distribution,and general plant
6	AMORT. OF UTILITY PLANT	-			-		100% commodity
7	Total Deprec. and Amort. Expense	$ 24,316,624	$ 8,313,989	$ 16,002,636	$ -	$ -	
	TAXES OTHER THAN INCOME TAXES:						
8	Revenue Related	$ (1,914,508)				$ (1,914,508)	100% revenue
9	Other	12,104,772	4,142,463	7,962,309	-		net plant
10	Total Taxes other than Income Taxes	$ 10,190,264	$ 4,142,463	$ 7,962,309	$ -	$ (1,914,508)	
11	REV.CRDT TO COS(NEG.OF OTHR OPR.REV)	$ (2,287,122)	$ (2,287,122)				100% customer
12	RETURN (REQUIRED NOI)	$ 61,694,517	$ 21,824,653	$ 39,800,752	$ 69,112		rate base
13	INCOME TAXES	$ 14,232,356	$ 5,034,746	$ 9,181,666	$ 15,943	$ -	return(noi)
14	TOTAL OVERALL COST OF SERVICE	154,770,062	66,571,348	88,708,768	1,404,455	(1,914,508)	

Supporting Schedules: E-1 p.3, G-2 p.1, G-2 p.23

Recap Schedules: H-3 p.1

Schedule H-3 | Cost of Service | Page 4 of 5

Florida Public Service Commission
Company: Florida City Gas
Docket No.: 20260026-GU

Explanation: Provide a fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Classification of Rate Base Accumulated Depreciation
Schedule I 2 of 2

Line No.		Total	Customer	Capacity	Commodity	Classifier
1	LOCAL STORAGE PLANT	$ (4,931,099)		$ (4,931,099)		related plant
2	INTANGIBLE PLANT	$ (5,019,128)		$ (5,019,128)		rel.plant account
3	PRODUCTION PLANT	-		-		"
	DISTRIBUTION PLANT:					
4	367 Transmission Mains	$ -		$ -		
5	374 Land and Land Rights	(9,204)		(9,204)		
6	375 Structures and Improvements	(37,091)		(37,091)		"
7	376 Mains	(122,484,699)	-	(122,484,699)		"
8	377 Compressor Sta. Eq.	-		-		"
9	378 Meas. & Reg. Sta. Eq.-Gen	(845,283)		(845,283)		"
10	379 Meas. & Reg. Sta. Eq.-CG	(5,631,339)		(5,631,339)		"
11	380 Services	(61,023,560)	(61,023,560)			"
12	381-382 Meters	(920,724)	(920,724)			"
13	383-384 House Regulators	(997,971)	(997,971)			"
14	385 Industrial Meas.& Reg.Eq.	(2,548,637)		(2,548,637)		"
15	386 Property on Customer Premises	-				"
16	387 Other Equipment	(988,284)	(319,822)	(668,462)	-	"
17	Total A.D. on Dist. Plant	$ (195,486,792)	$ (63,262,077)	$ (132,224,715)	$ -	
18	GENERAL PLANT	$ (13,619,316)	$ (6,809,658)	$ (6,809,658)		general plant
19	PLANT ACQUISITIONS	$ (16,362,943)		$ (16,362,943)		plant acquisitions
20	GENERAL COMMON PLANT	$ (3,454,300)	$ (1,727,150)	$ (1,727,150)		general common plant
21	RETIREMENT WORK IN PROGRESS:	$ 708,937	$ 260,563	$ 448,374		distribution plant
22	TOTAL ACCUMULATED DEPRECIATION	$ (238,164,641)	$ (71,538,322)	$ (166,626,319)	$ -	
23	NET PLANT (Plant less Accum.Dep.)	$ 713,024,383	$ 244,009,328	$ 469,015,055	$ -	
24	CUSTOMER ADVANCES	$ -	$ -	$ -		50%-50% cust--cap
25	WORKING CAPITAL	$ 29,388,571	$ 18,621,871	$ 9,935,031	$ 831,669	oper. and maint. exp.
26	TOTAL RATE BASE	$ 742,412,954	$ 262,631,199	$ 478,950,086	$ 831,669	

Supporting Schedules: G-1 p.1, G-1 p.4, G-1 p.12

Recap Schedules: H-3 p.1

Schedule H-3 | Cost of Service | Page 5 of 5

Florida Public Service Commission

Company: Florida City Gas

Docket No.: 20260026-GU

Explanation: Provide a fully allocated embedded cost of service study.

Type of Data Shown:
Projected Test Year: 12/31/2027
Witness: J. Taylor

Classification of Rate Base - Plant
Schedule I 1 of 2

Line No.		Total	Customer	Capacity	Commodity	Classifier
1	LOCAL STORAGE PLANT	$ 69,218,584		$ 69,218,584		100% capacity
2	INTANGIBLE PLANT	29,578,644		29,578,644		"
3	PRODUCTION PLANT	-		-		"
	DISTRIBUTION PLANT:					
4	367 Transmission Mains	$ -		$ -		"
5	374 Land and Land Rights	406,783		406,783		"
6	375 Structures and Improvements	335,399		335,399		"
7	376 Mains	423,757,413	-	423,757,413		"
8	377 Comp. Sta. Eq.			-		"
9	378 Meas. & Reg. Sta. Eq.-Gen	10,412,846		10,412,846		"
10	379 Meas. & Reg. Sta. Eq.-CG	14,245,306		14,245,306		"
11	380 Services	180,265,988	180,265,988			100% customer
12	381-382 Meters	73,912,678	73,912,678			"
13	383-384 House Regulators	10,941,090	10,941,090			"
14	385 Industrial Meas.& Reg.Eq.	4,647,714		4,647,714		100% capacity
15	386 Property on Customer Premises		-	-	-	ac 374-385
16	387 Other Equipment	3,368,289	1,242,132	2,126,157	-	ac 374-386
17	389 Land Genreal and Rights	2,420,226		2,420,226		100% capacity
18	Total Distribution Plant	$ 724,713,733	$ 266,361,888	$ 458,351,845	$ -	724713732.8
19	GENERAL PLANT	$ 43,629,643	$ 21,814,821	$ 21,814,821		50% customer,50%, capacity
20	GENERAL COMMON PLANT	33,515,879	16,757,939	16,757,939		50% customer,50%, capacity
21	PLANT ACQUISITIONS	21,656,835		21,656,835		100% capacity
22	GAS PLANT FOR FUTURE USE:	-		-		"
23	CWIP	28,875,708	10,613,002	18,262,706	-	dist.plant
24	TOTAL PLANT	$ 951,189,024	$ 315,547,650	$ 635,641,375	$ -	

Supporting Schedules: G-1 p.1, G-1 p.4, G-1 p.10

Recap Schedules: H-3 p.1

Line No.	Category Description	Total System	RS	RSG	GS - 1	GS - 2 (10K)	GS - 3 (50K)
1	**Total Rate Base**	**$ 742,412,954**	**$ 343,835,492**	**$ 227,226**	**$ 121,295,602**	**$ 108,398,431**	**$ 24,524,511**
2	**Revenue at Current Rates**						
3	Base Revenue	$ 91,496,185	$ 37,874,673	$ 23,200	$ 15,471,170	$ 13,829,899	$ 3,032,595
4	Transfer of Save Investments Revenues	16,402,944	15,167,225	-	944,340	256,731	16,674
5	**Subtotal Base Revenue at Current Rates**	**$ 107,899,129**	**$ 53,041,898**	**$ 23,200**	**$ 16,415,510**	**$ 14,086,630**	**$ 3,049,269**
6	Other Revenues	2,287,122	1,710,939	769	321,403	119,982	25,192
7	**Total Revenue at Current Rates**	**$ 110,186,251**	**$ 54,752,838**	**$ 23,969**	**$ 16,736,912**	**$ 14,206,611**	**$ 3,074,461**
8	Current Rate of Return	4.21%	2.69%	-2.65%	4.68%	4.81%	4.37%
9	Relative Rate of Return	1.00	0.64	(0.63)	1.11	1.14	1.04
10	Current Revenue to Cost Ratio	0.70	0.67	0.45	0.70	0.70	0.67
11	Current Parity Ratio	1.00	0.96	0.65	1.00	0.99	0.96
12	**Scenario 1: Revenues at Equalized Rates of Return**						
13	Base Revenue Increase/(Decrease)	$ 46,870,932	$ 26,567,327	$ 28,830	$ 7,125,103	$ 6,233,530	$ 1,512,118
14	Base Revenue at Current Rates	107,899,129	53,041,898	23,200	16,415,510	14,086,630	3,049,269
15	Other Revenues	2,287,122	1,710,939	769	321,403	119,982	25,192
16	**Total Revenue at Equalized Rates of Return**	**$ 157,057,184**	**$ 81,320,165**	**$ 52,799**	**$ 23,862,015**	**$ 20,440,141**	**$ 4,586,579**
17	**Rate Revenue at Equalized Rates of Return**	**$ 154,770,062**	**$ 79,609,225**	**$ 52,030**	**$ 23,540,612**	**$ 20,320,160**	**$ 4,561,387**
18	% Increase of Total Revenues	42.54%	48.52%	120.28%	42.57%	43.88%	49.18%
19	% Increase of Base Revenues	43.44%	50.09%	124.27%	43.40%	44.25%	49.59%
20	Resulting Revenue to Cost Ratio	1.00	1.00	1.00	1.00	1.00	1.00
21	Resulting Parity Ratio	1.00	1.00	1.00	1.00	1.00	1.00
22	**Scenario 2: Equal Percentage Increase on Service Revenue**						
23	Percent Increase	43.4%	43.4%	43.4%	43.4%	43.4%	43.4%
24	Base Revenue Increase/(Decrease)	$ 46,870,932	$ 23,041,180	$ 10,078	$ 7,130,829	$ 6,119,173	$ 1,324,590
25	Base Revenue at Current Rates	107,899,129	53,041,898	23,200	16,415,510	14,086,630	3,049,269
26	Other Revenues	2,287,122	1,710,939	769	321,403	119,982	25,192
27	**Total Revenue at Equal Percentage Increase**	**$ 157,057,184**	**$ 77,794,017**	**$ 34,047**	**$ 23,867,741**	**$ 20,325,785**	**$ 4,399,050**
28	**Rate Revenue at Equal Percent Increase**	**$ 154,770,062**	**$ 76,083,078**	**$ 33,278**	**$ 23,546,339**	**$ 20,205,803**	**$ 4,373,858**
29	Resulting Revenue to Cost Ratio	1.00	0.96	0.64	1.00	0.99	0.96
30	Resulting Parity Ratio	1.00	0.96	0.64	1.00	0.99	0.96

Line No.	Category Description	Total System	RS	RSG	GS - 1	GS - 2 (10K)	GS - 3 (50K)
31	**Scenario 3: Moderated based on Current Parity Ratio**						
32	Base Rate Base (Deficiency)/Surplus	46,870,932	26,567,327	28,830	7,125,103	6,233,530	1,512,118
33	Required Increase to Base Revenue	43.44%	50.09%	124.27%	43.40%	44.25%	49.59%
34	Required Multiple of System Increase		1.15	2.86	1.00	1.02	1.14
35	Proposed Multiple of System Increase		0.70	2.86	1.77	1.77	1.77
36	Proposed Percent Increase		30.41%	124.27%	77.05%	77.05%	77.05%
37	Proposed Base Revenue Increase/(Decrease)	$ 46,870,932	$ 16,128,826	$ 28,830	$ 12,647,548	$ 10,853,231	$ 2,349,350
38	**Total Base Revenue at Proposed Rates**	**$ 154,770,062**	**$ 69,170,724**	**$ 52,030**	**$ 29,063,058**	**$ 24,939,861**	**$ 5,398,618**
39	**Total Revenue at Proposed Rates**	**$ 157,057,184**	**$ 70,881,663**	**$ 52,799**	**$ 29,384,460**	**$ 25,059,843**	**$ 5,423,810**
40	Proposed Rate of Return	8.31%	5.84%	8.31%	12.01%	11.77%	11.08%
41	Relative Rate of Return	1.00	0.70	1.00	1.45	1.42	1.33
42	Proposed Revenue to Cost Ratio	1.00	0.87	1.00	1.23	1.23	1.18
43	Proposed Parity Ratio	1.00	0.87	1.00	1.23	1.23	1.18

Line No.	Category Description	GS - 4 (120K)	GS - 5 (1250K)	GS - 6 (11M)	GS - 7 (25M)	CSG	KDS	TPS	LES
1	**Total Rate Base**	**$ 120,883,528**	**$ 21,307,674**	**$ -**	**$ -**	**$ 1,940,491**	**$ -**	**$ -**	**$ -**
2	**Revenue at Current Rates**								
3	Base Revenue	$ 12,813,395	$ 3,653,286	$ -	$ -	$ 57,804	$ 3,246,230	$ 280,181	$ 1,213,751
4	Transfer of Save Investments Revenues	16,576	1,399	-	-	-	-	-	-
5	**Subtotal Base Revenue at Current Rates**	**$ 12,829,972**	**$ 3,654,685**	**$ -**	**$ -**	**$ 57,804**	**$ 3,246,230**	**$ 280,181**	**$ 1,213,751**
6	Other Revenues	106,878	-	-	-	1,960	-	-	-
7	**Total Revenue at Current Rates**	**$ 12,936,849**	**$ 3,654,685**	**$ -**	**$ -**	**$ 59,765**	**$ 3,246,230**	**$ 280,181**	**$ 1,213,751**
8	Current Rate of Return	2.58%	9.25%	0.00%	0.00%	-7.31%	0.00%	0.00%	0.00%
9	Relative Rate of Return	0.61	2.20	-	-	(1.74)	-	-	-
10	Current Revenue to Cost Ratio	0.58	0.91	-	-	0.15	-	-	-
11	Current Parity Ratio	0.82	1.30	-	-	0.22	-	-	-
12	**Scenario 1: Revenues at Equalized Rates of Return**								
13	Base Revenue Increase/(Decrease)	$ 9,467,480	$ 346,314	$ -	$ -	$ 330,392	$ (3,246,230)	$ (280,181)	$ (1,213,751)
14	Base Revenue at Current Rates	12,829,972	3,654,685	-	-	57,804	3,246,230	280,181	1,213,751
15	Other Revenues	106,878	-	-	-	1,960	-	-	-
16	**Total Revenue at Equalized Rates of Return**	**$ 22,404,329**	**$ 4,000,999**	**$ -**	**$ -**	**$ 390,157**	**$ -**	**$ -**	**$ -**
17	**Rate Revenue at Equalized Rates of Return**	**$ 22,297,451**	**$ 4,000,999**	**$ -**	**$ -**	**$ 388,197**	**$ -**	**$ -**	**$ -**
18	% Increase of Total Revenues	73.18%	9.48%	0.00%	0.00%	552.82%	-100.00%	-100.00%	-100.00%
19	% Increase of Base Revenues	73.79%	9.48%	0.00%	0.00%	571.57%	-100.00%	-100.00%	-100.00%
20	Resulting Revenue to Cost Ratio	1.00	1.00	-	-	1.00	-	-	-
21	Resulting Parity Ratio	1.00	1.00	-	-	1.00	-	-	-
22	**Scenario 2: Equal Percentage Increase on Service R**								
23	Percent Increase	43.4%	43.4%	43.4%	43.4%	43.4%	43.4%	43.4%	43.4%
24	Base Revenue Increase/(Decrease)	$ 5,573,286	$ 1,587,580	$ -	$ -	$ 25,110	$ 1,410,149	$ 121,710	$ 527,248
25	Base Revenue at Current Rates	12,829,972	3,654,685	-	-	57,804	3,246,230	280,181	1,213,751
26	Other Revenues	106,878	-	-	-	1,960	-	-	-
27	**Total Revenue at Equal Percentage Increase**	**$ 18,510,136**	**$ 5,242,264**	**$ -**	**$ -**	**$ 84,875**	**$ 4,656,379**	**$ 401,891**	**$ 1,740,999**
28	**Rate Revenue at Equal Percent Increase**	**$ 18,403,258**	**$ 5,242,264**	**$ -**	**$ -**	**$ 82,915**	**$ 4,656,379**	**$ 401,891**	**$ 1,740,999**
29	Resulting Revenue to Cost Ratio	0.83	1.31	-	-	0.22	-	-	-
30	Resulting Parity Ratio	0.83	1.31	-	-	0.22	-	-	-

Line No.	Category Description	GS - 4 (120K)	GS - 5 (1250K)	GS - 6 (11M)	GS - 7 (25M)	CSG	KDS	TPS	LES
31	**Scenario 3: Moderated based on Current Parity Rati**								
32	Base Rate Base (Deficiency)/Surplus	9,467,480	346,314	-	-	330,392	(3,246,230)	(280,181)	(1,213,751)
33	Required Increase to Base Revenue	73.79%	9.48%	0.00%	0.00%	571.57%	-100.00%	-100.00%	-100.00%
34	Required Multiple of System Increase	1.70	0.22	-	-	13.16	(2.30)	(2.30)	(2.30)
35	Proposed Multiple of System Increase	0.70	0.25	-	-	13.16	0.17	-	-
36	Proposed Percent Increase	30.41%	10.86%	0.00%	0.00%	571.57%	7.23%	0.00%	0.00%
37	Proposed Base Revenue Increase/(Decrease)	$ 3,901,300	$ 396,895	$ -	$ -	$ 330,392	$ 234,560	$ -	$ -
38	**Total Base Revenue at Proposed Rates**	**$ 16,731,272**	**$ 4,051,580**	**$ -**	**$ -**	**$ 388,197**	**$ 3,480,790**	**$ 280,181**	**$ 1,213,751**
39	**Total Revenue at Proposed Rates**	**$ 16,838,150**	**$ 4,051,580**	**$ -**	**$ -**	**$ 390,157**	**$ 3,480,790**	**$ 280,181**	**$ 1,213,751**
40	Proposed Rate of Return	4.57%	8.50%	0.00%	0.00%	8.31%	0.00%	0.00%	0.00%
41	Relative Rate of Return	0.55	1.02	-	-	1.00	-	-	-
42	Proposed Revenue to Cost Ratio	0.75	1.01	0.00	0.00	1.00	0.00	0.00	0.00
43	Proposed Parity Ratio	0.75	1.01	-	-	1.00	-	-	-

					Current			Proposed (Excluding ERP)								
Line No	Proposed Class Code	Number of Bills	Sales (Therms)	DCQ	Total Base Revenue	Multiple of System Increase	Revenue Increase %	Customer Charge Rate	Demand Charge	Distribution Charge	Customer Charge Revenue	Demand Charge Revenue	Distribution Charge Revenue	Total Base Revenue	Revenue Change ($)	Revenue Change (%)
1	RS	1,449,276	17,783,310	-	$ 53,041,898	0.70	26.4%	$ 36.50		$ 0.79473	$ 52,898,583	$ -	$ 14,132,865	$ 67,031,449	$ 13,989,551	26.4%
2	RSG	928	1,827	-	23,200	2.86	107.8%	$ 54.27		$ 0.79473	50,358	-	1,452	51,810	28,610	123.3%
3	CSG	1,606	19,691	-	57,804	13.16	495.9%	$ 231.58		$ 0.77500	371,838	-	15,260	387,099	329,294	569.7%
4	GS - 1	85,722	23,326,615	-	16,415,510	1.78	66.9%	$ 85.00		$ 0.86216	7,286,392	-	20,111,279	27,397,671	10,982,162	66.9%
5	GS - 2 (10K)	19,444	26,392,437	-	14,086,630	1.78	66.9%	$ 155.00		$ 0.77500	3,013,892	-	20,454,202	23,468,094	9,381,464	66.6%
6	GS - 3 (50K)	1,237	6,357,270	-	3,049,269	1.78	66.9%	$ 600.00		$ 0.68384	741,932	-	4,347,332	5,089,264	2,039,995	66.9%
7	GS - 4 (120K)	1,236	35,834,584	3,053,952	12,829,972	0.70	26.4%	$ 750.00	$ 0.9252	$ 0.34777	927,033	2,825,410	12,462,243	16,214,686	3,384,715	26.4%
8	GS - 5 (1250K)	104	17,457,355	1,574,040	3,654,685	0.25	9.4%	$ 1,250.00	$ 0.9252	$ 0.13824	129,555	1,456,247	2,413,223	3,999,025	344,341	9.4%
9	GS - 6 (11M)	-	-	-	-	-	0.0%	$ 2,500.00	$ 0.9252	$ 0.10137	-	-	-	-	-	0.0%
10	GS - 7 (25M)	-	-	-	-	-	0.0%	$ 5,000.00	$ 0.9252	$ 0.05069	-	-	-	-	-	0.0%
														-		
11	Special Contracts	72	53,829,080	950,567	4,740,162									4,924,609		
12	**Total**	**1,559,625**	**181,002,168**	**5,578,559**	**$ 107,899,129**						**$ 65,419,584**	**$ 4,281,658**	**$ 73,937,857**	**$ 148,563,708**	**$ 40,480,132**	**37.5%**
13	Water Heater Interest				$ 225,320									$ 225,320		
14	Late Payment Charges				$ 1,142,643									$ 1,142,643		
15	Miscellaneous Service Revenue				$ 826,685									$ 826,685		
16	NSF Charges				$ 92,475									$ 92,475		
17	**Total Other Revenue**				**$ 2,287,122**									**$ 2,287,122**		
18	**Total Revenue**				**$ 110,186,251**									**$ 150,850,830**		

19	**ERP Rev Req**	**$ 6,206,353**
20	**Revenue Increase ($)**	**$ 40,664,579**
21	**Revenue Increase (%)**	**37.7%**

John D. Taylor

CEO

Mr. John D. Taylor is the Co-Founder and Chief Executive Officer of Atrium Economics and a senior regulatory economist with more than twenty years of experience advising electric and natural gas utilities across the United States and Canada. Mr. Taylor has served as a lead expert in rate and regulatory proceedings across more than 20 jurisdictions in the United States and Canada. His testimony has been presented before the Federal Energy Regulatory Commission, numerous state public utility commissions, provincial utility regulators, and trial courts.

He has testified on matters including revenue requirements, class cost of service, advanced rate design, revenue stabilization mechanisms, affiliate transactions, demand forecasts, return on equity, lead lag studies, audit testing, and infrastructure cost recovery. In addition to matters in which he was the lead witness, he has supported over one hundred engagements for other expert witnesses, contributing to the development and defense of analytical models, regulatory strategy, and evidentiary submissions.

Mr. Taylor's experience spans vertically integrated electric utilities, gas distribution utilities, transmission providers, pipeline operators, municipally owned utilities, and multi-state holding companies. He has also served as market monitor for ISO New England's capacity market and has supported wholesale power purchase agreement evaluations and generation feasibility and prudence analyses. He regularly advises executive leadership and boards on regulatory strategy, risk allocation, revenue stability, infrastructure investment, and long-term rate design considerations.

In addition to his consulting leadership, Mr. Taylor served as Chief Executive Officer of a non-destructive testing and industrial inspection firm serving the power generation, petrochemical, and heavy industrial sectors. That role provided direct experience in capital-intensive infrastructure operations, asset integrity management, maintenance planning, safety compliance, and operational risk oversight. This operating perspective informs his work in utility capital planning, infrastructure expansion review, and regulatory cost recovery.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

20

RELEVANT EXPERTISE

Revenue Requirements & Capital Recovery, Class Cost of Service & Advanced Rate Design, Revenue Stabilization Mechanisms, Demand Forecasting & Resource Planning, Natural Gas & Pipeline Infrastructure Analysis, Return on Equity & Capital Structure, Affiliate Transactions & Operational Audits, Transmission & FERC Matters, Transaction Advisory & Regulatory Due Diligence

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Maryland Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- North Carolina – Brunswick Superior Court
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- South Carolina Public Service Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Taylor has extensive experience developing and evaluating utility revenue requirements, including review of test year construction, pro forma adjustments, operating expense normalization, capital investment recovery, depreciation and amortization treatment, and cash working capital analyses, including lead-lag studies. He has assessed prudence and regulatory treatment of major capital programs, infrastructure modernization initiatives, and incremental investment proposals. In addition, Mr. Taylor has designed and evaluated revenue stabilization mechanisms, including Weather Normalization Adjustments, Revenue Adjustment Mechanisms, and other forms of decoupling and revenue recovery tools. His work includes back-casting analyses, risk assessment modeling, and evaluation of tradeoffs between customer bill stability and utility revenue certainty. He has testified regarding both the technical design and policy implications of such mechanisms in contested regulatory proceedings.

CLASS COST OF SERVICE AND RATE DESIGN

Mr. Taylor has extensive experience developing and defending embedded and marginal class cost of service studies in contested regulatory proceedings across the United States and

Canada. His work includes functionalization, classification, and allocation of utility costs; development of jurisdictional and class revenue requirements; and evaluation of fixed-variable cost recovery methodologies. He has designed and evaluated residential, commercial, and industrial rate structures, including demand-based rates, time-of-use designs, economic development tariffs, and revenue apportionment strategies. Mr. Taylor has also assessed rate stability, equity considerations, and cost causation principles in the context of evolving load patterns, electrification, and policy-driven rate reforms.

DEMAND AND CUSTOMER FORECASTING

Mr. Taylor has extensive experience developing and evaluating demand and customer forecasting models for electric and natural gas utilities. His work includes econometric modeling of customer growth, usage normalization, peak demand forecasting, and weather-sensitive load analysis. He has assessed forecast methodologies for rate proceedings, infrastructure planning, and resource adequacy evaluations, including review of macroeconomic drivers, demographic trends, and end-use consumption patterns. Mr. Taylor has also evaluated forecast inputs used in capital planning, pipeline capacity assessments, LNG resource planning, and revenue requirement development. His experience includes back-casting analyses, scenario modeling, and sensitivity testing to assess forecast risk and regulatory defensibility. He has testified regarding forecast methodology, assumptions, and alignment with regulatory standards in contested proceedings.

RETURN ON EQUITY AND CAPITAL STRUCTURE

Mr. Taylor has provided testimony and advisory analysis regarding return on equity and capital structure for regulated electric and natural gas utilities in both transmission and distribution contexts. His work includes evaluation of regulatory capital structures, cost of capital components, and risk considerations associated with infrastructure investment, revenue stability mechanisms, and business model evolution. He has supported financial modeling in rate proceedings, including assessment of cash flow implications, earnings stability, and alignment between authorized returns and underlying business risk. Mr. Taylor has also evaluated the interaction between capital structure, revenue recovery mechanisms, and regulatory policy objectives, including the treatment of large capital programs and expansion initiatives.

TRANSACTION ADVISORY AND REGULATORY DUE DILIGENCE

Mr. Taylor has advised utilities and infrastructure stakeholders in connection with asset acquisitions, divestitures, and wholesale power supply evaluations. His transaction experience includes regulatory due diligence, evaluation of revenue requirements and rate structures, infrastructure risk assessment, and financial modeling to support investment decisions. Mr. Taylor has advised on regulated utility and energy infrastructure transactions, including buy-side and sell-side evaluation of utility operations and generation asset divestitures. His work has

included assessment of revenue requirements, rate structures, customer forecasts, regulatory risk, operational performance, and capital recovery considerations to support informed investment decisions. His advisory work has also included evaluation of comparable utility transactions, merger activity, and regulatory approval considerations affecting infrastructure investment decisions.

NATURAL GAS INFRASTRUCTURE & RESOURCE PLANNING EXPERIENCE

Mr. Taylor has extensive experience supporting natural gas utilities and pipeline operators in forecasting, peak demand planning, LNG resource evaluation, balancing mechanisms, transportation modeling, and line extension reviews. His work includes demand forecasting for local distribution companies, evaluation of peak day planning standards, LNG peaking facility analyses, storage utilization review, pipeline transport cost allocation, and balancing service design. He has evaluated integrated resource planning approaches, supply portfolio risk assessment, and incremental pipeline capacity expansion proposals. His experience includes review of expansion economics, regulatory treatment of new infrastructure investment, and cost recovery mechanisms associated with large capital programs. Mr. Taylor has also assessed alignment between demand forecasts, contracted capacity, storage strategy, and long-term system reliability objectives, providing analytical support for regulatory filings and board-level capital planning decisions.

AFFILIATE RELATIONSHIPS & PERFORMANCE REVIEWS

Mr. Taylor has led and supported affiliate transaction reviews, shared services cost allocation studies, and operational performance assessments in both U.S. and Canadian jurisdictions. His work includes evaluation of overhead allocation methodologies, overhead capitalization practices, and cost recovery treatment associated with corporate support functions, transmission-related shared assets, and early contractor engagement for major infrastructure projects. He has assessed capitalization rates, allocation between transmission and distribution functions, and cost attribution to regulated versus affiliate activities, ensuring consistency with regulatory standards and precedent. His experience includes shared assets studies, evaluation of contractor cost structures in large capital programs, and review of governance controls supporting regulatory compliance. In addition, Mr. Taylor has conducted operational audits and benchmarking analyses addressing operations and maintenance (O&M) and administrative and general (A&G) expenses. His work includes comparative peer analysis, assessment of cost drivers, and evaluation of organizational efficiency and cost discipline in regulated utility environments.

PROFESSIONAL EXPERIENCE

CO-FOUNDER & CHIEF EXECUTIVE OFFICER | ATRIUM ECONOMICS | 2020 – PRESENT

Leads a regulatory advisory firm serving electric and natural gas utilities across the United States and Canada. Serves as lead expert witness in rate and regulatory proceedings and oversees firm strategy, analytical methodology, and evidentiary quality control. Advises executive leadership and boards on revenue requirements, rate design, infrastructure investment, and regulatory risk.

CHIEF EXECUTIVE OFFICER | NOVA DATA TESTING | 2019 – 2026

Led a non-destructive testing and industrial inspection firm serving power generation and petrochemical facilities. Responsible for strategic planning, capital allocation, regulatory compliance, operational leadership, and risk oversight in asset-intensive, safety-sensitive environments. This operating experience informs his perspective on infrastructure investment and cost recovery matters.

PRINCIPAL CONSULTANT | BLACK & VEATCH MANAGEMENT CONSULTING | 2015 – 2020

Led regulatory and financial advisory engagements for electric and gas utilities, including revenue requirements, class cost of service, affiliate transactions, and return on equity matters. Filed expert testimony and supported infrastructure transaction advisory and regulatory approval strategy.

SENIOR PROJECT MANAGER & PRINCIPAL | CONCENTRIC ENERGY ADVISORS | 2006 – 2015

Managed regulatory consulting engagements involving revenue requirements, cost allocation, and rate design across multiple jurisdictions. Led project teams, supported expert testimony, and contributed to business development and firm-wide analytical quality control initiatives.

EDUCATION

MASTER OF ARTS, ECONOMICS| AMERICAN UNIVERSITY | 2004 – 2006

Graduate coursework included econometrics, advanced microeconomics and macroeconomics, mathematical economics, monetary policy, and history of economic thought. Served as a teaching assistant for undergraduate microeconomics and macroeconomics courses.

BACHELOR OF ARTS, ENVIRONMENTAL ECONOMICS | UNIVERSITY OF NORTH CAROLINA AT ASHEVILLE | 2000 – 2004

Coursework emphasized the application of economic theory and quantitative analysis to environmental and resource issues, including statistics and applied modeling. Completed independent study examining the intersection of ethics and economic theory.

BOARD AND ADVISORY BOARDS

Treasurer, Board of Directors – The Outside Foundation (2023–Present)

Member – 278 Gateway Corridor Committee, Town of Hilton Head Island (2019–2022)

Richmond Advisory Board – Higher Achievement (2014–2015)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Testimony and Exhibits of John Taylor have been furnished by Electronic Mail to the following parties of record this 20th day of April, 2026:

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