BOOK III

UGI UTILITIES, INC. – ELECTRIC DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI ELECTRIC STATEMENT NO. 6 – JOHN D. TAYLOR
UGI ELECTRIC STATEMENT NO. 7 – JOHN F. WIEDMAYER
UGI ELECTRIC STATEMENT NO. 8 – DARIN T. ESPIGH
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UGI UTILITIES, INC. – ELECTRIC DIVISION
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UGI ELECTRIC STATEMENT NO. 6

JOHN D. TAYLOR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 6

Direct Testimony

of

John D. Taylor, Managing Partner
Atrium Economics, LLC

Topics Addressed:	**Cost of Service**
	Revenue Allocation
	Rate Design

Dated: January 27, 2023

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I. INTRODUCTION

Q. Please state your name, affiliation, and business address.

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. Please describe your professional background and education.

A. As a utility pricing and policy expert, I am involved in various energy and utility-related projects regarding economics, finance, and public policy. Part of my role within these projects is to conduct various analyses considering accounting and financial factors and the particular operational configuration of a company's assets. I have presented expert testimony in state public utility regulatory proceedings in Indiana, Maine, Minnesota, Illinois, Delaware, Pennsylvania, Washington, West Virginia, British Columbia, and the Federal Energy Regulatory Commission ("FERC"). I began my education studying electrical and mechanical engineering and worked for an industrial inspection company, which provided me with hands-on experience with electric utility assets and equipment. I received an undergraduate degree in Environmental Economics, with an emphasis in econometrics and regulatory policy. I also earned a Master's in Economics from American University in Washington, DC. A copy of my resume is provided as UGI Electric Exhibit JDT-1.

Q. What is the purpose of your testimony in this proceeding?

A. I prepared and am sponsoring UGI Utilities, Inc. – Electric Division's ("UGI Electric" or the "Company") fully allocated cost of service study used in this case to develop the allocated costs of service study ("ACOSS" or "COSS"), which is found in UGI Electric Exhibit D. The ACOSS allocates the Company's cost of service associated with Pennsylvania Public Utility Commission ("Commission") jurisdictional operations to the Company's retail customer classes. I also support the allocation, or apportionment, of the class revenue increase and the Company's rate design proposal.

Q. Please summarize the content of your testimony.

First, I provide an overview of the ACOSS, including various principles and factors that influence the cost allocation framework, and general methods and approaches used to allocate costs to customer classes. Second, I discuss the underlying methodology and basis used in the ACOSS studies I conducted and am sponsoring for UGI Electric. I describe the studies of relative costs and other analyses employed to apportion the various categories of plant and operation and maintenance ("O&M") expenses to the respective customer classes. I present the class-by-class rate of return results and corresponding revenue surpluses or deficiencies from the ACOSS. Finally, I discuss the apportionment of the rate increase to the various rate classes and the customer-related costs and support for customer charges.

Q. Mr. Taylor, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Book IX, labeled as UGI Electric Exhibit D – Allocated Cost of Service Study (Fully Projected) ("Exhibit D"). Exhibit D contains three sections for which an index is provided on page 2 of Exhibit D. I also am sponsoring portions of Book II, Section 53.51 et seq. of the Commission's Regulations, Part IV-Rate Structure and Cost Allocation.

Q. Would you briefly describe the contents of Exhibit D?

A. Exhibit D provides the information required under 52 Pa. Code § 53.53(a)(3) and, in particular, Exhibit C - Electric utilities, Part IV (Rate Structure and Cost Allocation), Section E (1), by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(3), Exhibit C. IV. E(1). The studies contained in UGI Electric Exhibit D are based on costs and operating conditions for the fully projected future test year ("FPFTY") ending September 30, 2024.

Exhibit D consists of three sections detailing the process of developing the COSS. *Section I – Introduction* includes an introduction, the general purpose and process of the cost of service study, as well as an overview of the excel-based fully functional COSS model presented in this proceeding. *Section II – UGI's Cost of Service Procedures* presents the COSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section

II.4) describes all internal and external allocation factors and the allocation processes used in the COSS. The last section, *Section III – UGI's Cost of Service Results* depicts the results of the cost of service studies, including revenue requirement apportionment, comparison of cost of service with revenues under present and proposed rates, and development of rate of return by customer class under present and proposed rates.

Q. Please describe the schedules included in Exhibit D.

A. The following is the list of Schedules included in Exhibit D:

- Schedule 1 - Account Balances and Allocation Methods
- Schedule 2 - Functional Split & Minimum System Study
- Schedule 3 - External Allocation Factors
- Schedule 4 - Internal Allocation Factors
- Schedule 5 - Comparison of Cost of Service with Revenues Under Present and Proposed Rates
- Schedule 6 – Summary of Cost of Service and Rate of Return Under Present and Proposed Rates
- Schedule 7 - Cost of Service Allocation Study Detail by Account
- Schedule 8 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

II. OVERVIEW OF ALLOCATED COST OF SERVICE STUDY

Q. What are the general purposes and use of the ACOSS in this base rate proceeding?

The purpose of the ACOSS is to allocate UGI Electric's Commission-jurisdictional overall adjusted FPFTY revenues and costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. This is accomplished by analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the FPFTY. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility. The requirement to develop a COSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes or the cost of providing multiple products to the same rate class, using the same facilities, and the use by one rate class precludes the use by another rate class. In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of electric demand, while variable costs change directly with changes in demand. Most non-fuel-related utility costs are fixed in the short run and do not vary as customer loads change. This includes the cost of poles and towers, distribution conductors, transformers, service lines, and meters. While these costs increase due to inflationary pressures, this equipment is purchased, installed, and used to serve customers based on their requirements; and once placed into service, the costs of this equipment do not vary as a result of changes in customer loads. Finally, the COSS contributes to developing economically efficient rates and the cost responsibility by rate class. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue 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. Is the preparation of a cost allocation study an exact science?

A. No, it is not. The fundamental purpose of a cost allocation study is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. This process inherently requires a substantial level of judgment. The allocation of costs using a COSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. In general, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. 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 revenues that equate to the level of the revenue requirement.

Q. What is the guiding principle that should be followed when performing an ACOSS?

A. The ACOSS analysis intends to establish cost responsibility among the utility's various customer classes. The analysis should result in an appropriate allocation of the utility's total revenue requirement among the various customer classes. The most important theoretical principle underlying an ACOSS is that cost incurrence should follow cost causation. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. How do you establish the cost and utility service relationships?

A. 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. To accomplish this, I reviewed UGI Electric's expense and plant accounts, developed studies of the relative costs of providing facilities and services for each rate class, and analyzed the key factors that cause the costs to vary.

Q. What are the steps to performing an ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the predicate for an ACOSS are (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. Please describe cost functionalization.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. UGI Electric's primary functional cost categories associated with electric distribution services include Primary Distribution, Secondary Distribution, and Customer Accounts and Services. In addition, various categories of costs within the distribution function are assigned to separate sub-functions to the extent their costs vary in response to different customer class characteristics. Indirect costs that support these functions, such as General Plant and Administrative and General Expenses, are allocated to functions using allocation factors related to plant and/or labor ratios.

Q. Please describe cost classification.

A. The second step, classification of costs, further separates the functionalized plant and expenses according to the primary factors determining the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the system; and (3) the amount of electricity consumed by customers. These classification categories have been identified for purposes of the ACOSS as (1) Customer Costs, (2) Demand Costs, and (3) Energy Costs, respectively.

Q. Please describe the types of costs in the Customer, Demand, and Energy Costs categories.

A. ***Customer Costs*** are incurred to extend service to and attach a customer to the distribution system, meter electric usage, and maintain the customer's account. Customer Costs largely depend on the number of customers served and continue to be incurred whether or not the customer uses any electricity. They also include capital costs associated with minimum size distribution systems, services, meters, and customer billing and accounting expenses.

Demand Costs are capacity-related costs associated with plant that is designed, installed, and operated to meet maximum hourly or daily electric usage requirements, such as generating plants, transmission lines, transformers, substations, or more localized distribution facilities that are designed to satisfy individual customer maximum demands.

Energy Costs vary with the amount of kilowatt hours ("kWh") sold to customers. However, UGI Electric's distribution costs are fixed with respect to energy usage, and none of the remaining delivery service cost structure is energy-related.

Q. What is required to appropriately classify costs as Customer, Demand, and Energy?

A. Usually, a determination on the classification of costs can be made simply by knowing the type of activities or assets that reside in a particular FERC account. In these instances, the account as a whole can be classified. However, for some FERC account functions, it is beneficial to conduct classification studies to determine the portion of an account associated with each classification.

Q. Are there generally accepted methods for preparing classification studies?

A. The generally accepted methods are set forth in the National Association of Regulatory Utility Commissioners ("NARUC") Cost Allocation Manual ("NARUC Manual").[1] My ACOSS adheres to these cost allocation principles to classify the Company's distribution capital and operating costs. The NARUC Manual (pgs. 96-98) specifically states that an electric utility's distribution-related facilities are, from a design and operational basis, sized to meet the maximum kW load (demand) requirements of customers. Moreover, the NARUC Manual (pg. 89) also states that all distribution costs should be classified as either customer-related or demand-related or a combination of these two factors. To achieve this classification result, UGI Electric's distribution capital and operating costs are functionalized into their primary and secondary voltage level components. These primary and secondary voltage level capital and operating costs are then classified based on a "minimum size system" study, which identifies the portion of those costs required to serve a customer with minimum or no load, and that portion of the costs is allocated on a customer basis. The remaining portion of the costs is allocated on a demand basis, i.e., based on each rate class's average monthly contribution to the sum of the average monthly maximum demands for all classes. The average monthly demand is computed by

[1] National Association of Regulatory Utility Commissioners, "Electric Utility Cost Allocation Manual", 1992.

averaging a class's maximum non-coincident peak ("NCP") demand across all twelve months (i.e., the class's maximum energy demand during each month in a given hour; an hour of time that may not correspond to the system peak).

Q. Do all experts accept this classification approach?

A. No, they do not. Some experts take issue with the "minimum size system" study approach. They assert that the demand allocators produced by this type of study reflect certain equipment with some load-carrying capability; they suggest that the zero-intercept method may produce a better result. Others contend that some portion of the distribution system's fixed components (e.g., poles, conductors, services) should be classified on an energy basis. They also assert that the customer component is overstated and that the demand component is understated.

Q. Why do you support the use of the minimum size system approach?

A. The cost allocation methodology utilized in the minimum system studies is based on the specific design and operating characteristics of the Company's distribution system. It provides a more accurate and consistent measure of class cost responsibility than other approaches for providing distribution service to its customers. In other electric distribution cases where I developed and/or testified on an ACOSS, a similar method was employed to develop a minimum system study, notably in UGI Electric's recent base rate cases at Docket Nos. R-2017-2640058 and R-2021-3023618 and in PPL Electric Utilities

Corporation's ("PPL") base rate case at Docket No. R-2015-2469275. Further, the proposed "minimum size system" study, set forth in UGI Electric Exhibit D, is based on the same methodology and criteria that this Commission accepted in both of the fully-litigated proceedings at Docket Nos. R-2017-264008 and R-2015-2469275. As mentioned above, this method was explicitly approved and cited in the final orders by this Commission in those proceedings.

Q. Please describe the cost allocation process.

A. The final step, cost allocation, is the allocation of each functionalized and classified cost element to the rate class (or classes) that benefits from the cost. Customers are generally divided into customer classes based on the type and character of services they require. Costs are typically allocated to these customer classes based on the number of customers and the capacity required to serve the customer class. For example, much of the plant and equipment cost is related to the peak demand of the customers in each class, and these costs were accordingly allocated based on the average NCP demands of the rate class. Other portions of the cost depend upon the number of customers on the system, and these costs were allocated on a customer, or weighted-customer, basis.

Q. How does the cost analyst establish the fully-allocated costs related to various utility services?

A. To establish these relationships, the cost analyst must analyze a utility's electric system design, physical configuration and operations, accounting records, and system and customer load data. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. Please explain the considerations in determining the cost allocation methodologies used to perform an ACOSS.

A. As stated above, to allocate costs within any cost of service study, the factors that cause the costs to be incurred must be identified and understood. The availability of data for use in developing alternative cost allocation factors is also a consideration. In evaluating any cost allocation methodology, appropriate consideration should be given to whether it provides a sound rationale or theoretical basis, whether the results reflect cost causation and are representative of the costs of serving different types of customers, as well as the stability of the results over time.

III. UGI ELECTRIC'S ALLOCATED COST OF SERVICE STUDY

Q. What is the source of the cost data analyzed in UGI Electric's ACOSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., basic rate revenue requirement) contained in this general rate case filing for the FPFTY ending September 30, 2024. 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. How are UGI Electric's rate classes structured for the purposes of conducting its ACOSS?

A. For UGI Electric's ACOSS, I included six rate classes:

- Residential (Rate Schedule R)
- General Service (Rate Schedules GS-1 and GS-5)
- General Service-4 (Rate Schedule GS-4)
- Flood Control Power (Rate Schedule FCP)
- Large Power (Rate Schedule LP)
- Lighting (Rate Schedules OL, SL, SOL, SSL, MHOL, MHSL, and LED-OL)

In the past, UGI Electric's Flood Control Power ("FCP") Rate was included in the General Service-4. As part of the settlement agreement approved in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618, UGI Electric was required to "either eliminate, consolidate, or otherwise support Rate FCP as a separately identified class in the cost of service presented in the Company's next rate case."[2] The FCP customers are served directly from the primary system and have paid for dedicated transformers and services, which results in FCP only being allocated costs upstream of the secondary system and the cost of meters. Given the nature of the cost to serve the FCP customers, the decision was made to keep the FCP class as a separate tariffed rate class. As such, the ACOSS presented in this filing contains a separately identified class for the FCP Rate.

[2] See *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2021-3023618, et al., p. 13 (Opinion and Order entered Oct. 28, 2021) (quoting Paragraph 48 of the Joint Petition for Approval of Settlement of All Issues).

Q. Please explain how UGI Electric's Pennsylvania jurisdictional costs are derived.

A. This filing is based on the investment and expense incurred to provide distribution service to UGI Electric's Pennsylvania jurisdictional customers. Certain costs associated with UGI Electric's provision of transmission service under an open access transmission tariff administered by PJM Interconnection, LLC ("PJM") are recoverable from PJM through an annual formulary revenue requirement filing approved by the FERC. The costs subject to recovery through this FERC-jurisdictional rate mechanism were excluded to identify UGI Electric's Commission-jurisdictional distribution costs. Once UGI Electric completed this assignment, I utilized UGI Electric's cost of service specific to its Pennsylvania-jurisdictional retail customers.

Q. Please describe the Atrium Model used in conducting the ACOSS filed in this proceeding.

A. UGI Electric has selected the Atrium Excel-based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. The Atrium ACOSS Model was developed by Atrium on a proprietary basis for its consulting engagements and has been used in multiple jurisdictions. This is the same Atrium ACOSS Model that UGI Electric presented and that I sponsored in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618. Further, there are no material differences, in output and format, between the Atrium ACOSS Model used in this case and the past ACOSS model that UGI Electric presented and I sponsored in UGI Electric's 2018 base rate case at Docket No. R-2017-2640058.

Q. Does the methodology utilized in the current cost allocation study and supporting analyses match the methods used in UGI Electric's 2021 base rate case at Docket No. R-2021-3023618 and UGI Electric's 2018 base rate case at Docket No. R-2017-2640058?

A. Yes. The current ACOSS presented with this filing and proposed for use for decisions on the apportionment of the class revenue increases and rate design reflects the same methods utilized in UGI Electric's 2018 and 2021 base rate cases.

Q. Did the Commission opine on the appropriateness of these ACOSS methods?

A. Yes. In the UGI Electric 2018 base rate case (Docket No. R-2017-2640058), the Commission explicitly adopted UGI Electric's ACOSS and rejected the alternative proposed by the Office of Consumer Advocate ("OCA"), stating the following in the final order:

> Additionally, as UGI and the OSBA both highlighted, the Commission has affirmed the use of the "minimum system method" as the accepted approach to classify and allocate distribution system costs in several proceedings. See 2012 PPL Order, supra; see also, Pa. PUC v. PPL Electric Utilities Corp., Docket No. R-2010-2161694, (Order entered December 21, 2010) (2010 PPL Order). Further, we find that UGI's ACOSS is consistent with the NARUC Manual and more accurately reflects cost-causation principles than the ACOSS methodology proposed by the OCA.[3]

[3] *Pa. PUC v. UGI Utilities, Inc. – Electric Division*, Docket Nos. R-2017-2640058, *et al.*, p. 160 (Order entered Oct. 25, 2018).

Q. How did you functionalize and classify UGI Electric's Pennsylvania-jurisdictional distribution costs?

A. The process started with each of the Company's FERC accounts, which were assigned to a specific function. In some instances, the costs in an account were first split into separate functions or classifications if the costs in the account were incurred to perform more than one function or the costs in an account varied significantly with respect to more than one factor. For example, the accounts for distribution system poles, towers and fixtures, and conductors and conduits were separated into two functions: primary distribution and secondary distribution. In addition, these costs were further separated into demand and customer classifications. The functionalization and classification studies are provided in Section I of UGI Electric Exhibit D. It should be noted that the functionalization and classification of distribution plant investments and expenses are based on a detailed analysis of specific UGI Electric plant records and cost data.

Q. What cost assignment and allocation method was utilized in your studies?

A. I utilized the class average monthly maximum NCP demand to allocate demand-related distribution costs. Section II of UGI Electric Exhibit D presents the results of studies using other demand allocation methods, as required under the Commission's regulations. Further, the various customer-based allocation factors were developed utilizing Company records and data, including a meter investment allocation study and a services investment allocation study. Both are described in further detail and provided within Section II of UGI Electric Exhibit D.

Q. Please summarize the results of the Company's ACOSS.

A. Table 1 below presents a summary of the Company's ACOSS that can be reviewed in Schedule 1 of Book IX, UGI Electric Exhibit D. The ACOSS shows an overall revenue deficiency to the Company of $11.425 million.

Table 1 - Summary Results of the Company's ACOSS ($000)[4]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess
Residential	$ 117,080	$ 131,771	$ (14,691)
General Service	6,647	7,386	(739)
General Service-4	14,321	13,161	1,160
Flood Control Power	19	24	(5)
Large Power	11,680	9,469	2,211
Lighting	1,843	1,203	639
Subtotal	**$ 151,589**	**$ 163,014**	**$ (11,425)**
Other Revenues	$ 1,102	$ 1,102	-
Total System	**$ 152,691**	**$ 164,116**	**$ (11,425)**

Table 1 presents the revenue deficiency/excess for each rate class and the class rate of return on the net rate base at present rates. Regarding rate class revenue levels, the ACOSS results show that the Residential, General Service, and Flood Control Power rate classes are being charged rates that recover less than their indicated costs of service, whereas rates for other rate classes provide for recovery of more than the indicated costs of serving these other rate classes. Next, I explain how these ACOSS results guided the Company's determination of the revenues by rate class and the proposed rate levels.

[4] See Exhibit D, Schedule 6 lines 18, line 58, and line 59. Other Revenues is the sum of lines 13 and 14 shown at line 57.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the rate design principles utilized in developing the Company's rate design proposals.

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 and rate levels within rate classes, relies upon principles that have broad acceptance in the recognized literature on utility ratemaking and regulatory policy, including:

1. Cost of Service;
2. Efficiency;
3. Value of Service;
4. Stability/Gradualism;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[5] Each of these principles plays an important role in analyzing the rate design proposals of UGI Electric. In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[6] where the Commonwealth Court indicated that cost of

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[5] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.
[6] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

service is the “polestar” of ratemaking but that other factors, including those listed above, can be considered as well.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes. These principles can compete with each other, and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. There are tensions between the cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between the value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

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.

V. <u>ALLOCATION OF THE REVENUE INCREASE</u>

Q. Please describe the approach generally followed in allocating UGI Electric's proposed revenue increase of $11.452 million to its various rate classes.

A. To reflect the results of the class cost-of-service study, the Company is proposing to move all rate classes closer to the overall system rate of return and, as a result, reduce the current subsidies occurring between classes. This movement of classes towards the overall system rate of return is consistent with regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement of that case.

Q. Please describe the proposed approach to apportion UGI Electric's proposed revenue increase to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time while addressing issues of gradualism. The decision was made to provide no rate decreases to classes when other classes are facing increases. As such, the rate increase was spread across three classes Residential, General Service, and Flood Control Power. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the percentage change in the subsidies occurring between classes. With these considerations, the Company is proposing the revenue increases shown in Table 2 below.

In addition, Table 3 below provides the proposed revenue increase and the resulting percentage change in distribution operating revenues.

Table 2 – Proposed Class Revenue Apportionment ($000)[7]

Customer Classes	Current Revenues	Proposed Revenue	Proposed Revenue Change	Proposed Percentage Change
Residential	$ 117,080	$ 127,785	$ 10,705	9.1%
General Service	6,647	7,361	714	10.7%
General Service-4	14,321	14,321	-	0.0%
Flood Control Power	19	24	5	27.7%
Large Power	11,680	11,680	-	0.0%
Lighting	1,843	1,843	-	0.0%
Subtotal	**$ 151,589**	**$ 163,014**	**$ 11,425**	7.5%
Other Revenues	$ 1,102	$ 1,102	-	
Total System	**$ 152,691**	**$ 164,116**	**11,425**	7.5%

Table 3 – Proposed Change in Distribution Operating Revenue by Rate Class ($000)[8]

Customer Classes	Current Distribution Operating Revenue	Proposed Distribution Operating Revenue	Proposed Revenue Change	Proposed Percentage Change
Residential	$ 38,996	$ 49,701	$ 10,705	27.5%
General Service	2,718	3,433	$ 714	26.3%
General Service-4	5,084	5,084	$ -	0.0%
Flood Control Power	19	24	$ 5	27.7%
Large Power	6,617	6,617	$ -	0.0%
Lighting	1,262	1,262	$ -	0.0%
Subtotal	**$ 54,695**	**$ 66,120**	**$ 11,425**	20.9%
Other Revenues	$ 1,102	$ 1,102	-	0.0%
Total System	**$ 55,798**	**$ 67,223**	**11,425**	20.5%

[7] See Exhibit D, Schedule 6, line 18, line 65, line 60, line 67.
[8] See Exhibit D, Schedule 6, line 12, line 64, line 60, line 68.

Q. To what degree does the Company's proposed revenue apportionment move the classes toward their cost of service?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes and moves classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable such that class revenues and rates are closer to the indicated cost of service for each rate class.

Table 4 below compares the rate of return and relative rate of return under current and proposed class revenue levels. The percent change for the Residential, General Service, and Flood Control classes equals 74%.

Table 4 - Comparison of Relative Rate of Return by Rate Class[9]

Customer Classes	Current Rate of Return On Net Rate Base	Current Relative Rate of Return	Proposed Rate of Return on Net Rate Base	Proposed Relative Rate of Return	Percent Change
Residential	-0.18%	(0.05)	5.95%	0.73	74%
General Service	3.23%	0.86	7.85%	0.96	74%
General Service-4	17.29%	4.59	14.53%	1.78	78%
Flood Control Power	4.42%	1.17	8.51%	1.04	74%
Large Power	22.68%	6.02	19.07%	2.34	73%
Lighting	38.14%	10.12	31.87%	3.91	68%
Total Company	**3.77%**	**1.00**	**8.15%**	**1.00**	

[9] Exhibit D, Schedule 6, line 29, line 30, line 73, line 74. Percent Change = Proposed Relative Rate of Return/(1-Current Relative Rate of Return).

Q. To what degree does the Company's proposed revenue apportionment decrease the existing subsidies between rate classes?

A. Table 5 below summarizes the current and proposed subsidies and the reduction in all customer classes' subsidies resulting from the Company's proposed revenue apportionment.

Table 5 - Comparison of Present and Proposed Subsidies ($000) [10]

Customer Classes	Current Class Subsidy	Proposed Class Subsidy	Reduction in Subsidy
Residential	(6,237)	(3,986)	2,251
General Service	(59)	(25)	34
General Service-4	2,129	1,160	970
Flood Control Power	0.778	0.668	0.110
Large Power	3,352	2,211	1,140
Lighting	814	639	175

VI. UGI ELECTRIC'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes UGI Electric has proposed in this rate proceeding.

A. In general, UGI Electric's rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide electric distribution service to those customers. UGI Electric has proposed the following rate design changes to its current tariff schedules:

- Residential – Increase in the Monthly Customer Charge from $9.50 to $13.50, with the remaining proposed increase to be recovered in the Volumetric Charge.

[10] See Exhibit D, Schedule 6, line 40, line 66. Reduction in Subsidy = Absolute difference between Proposed Subsidy and Current Subsidy.

- General Service – Increase in the Monthly Customer Charge from $13.00 to $14.00, with the remaining proposed increase to be recovered in the Volumetric Charge.
- General Service-4 – No changes proposed.
- Flood Control Power – Recover the proposed increase in the volumetric charges.
- Large Power – No changes proposed.
- Lighting – No changes proposed.

Q. Has the Company prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?

A. Yes. UGI Electric Exhibit E – Proof of Revenue, sponsored by Company witness Sherry A. Epler, presents a detailed comparison of present and proposed revenues for each of UGI Electric's rate classes.

Q. What insight does the ACOSS provide concerning the development of the Residential customer charge?

Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. Table 6 below provides this information for the Residential class at the proposed rate increase.

Table 6 - Components of Residential Customer-Related Revenue Requirement[11]

Customer Portion of Residential Revenue Requirement		
Function	**Amount**	**Includes**
Total Customer Related Costs	**$ 43,536,966**	
USP Rider Costs	**$ 6,656,204**	
Total Customer Related Costs Less USP	**$ 36,880,762**	Customer Portion of Distribution
Annual Bills (Customer Count * 12)	659,976	Facilities
Unit Costs	**$ 55.88**	PA PUC Direct Customer Costs
Function	**Amount**	**Includes**
Distribution Facilities - Customer Portion	**$ 22,050,615**	
Annual Bills (Customer Count * 12)	659,976	Distribution Primary
Unit Costs	**$ 33.41**	Distribution Secondary
Function	**Amount**	**Includes**
PA PUC Direct Customer Costs	**$ 21,486,351**	
USP Rider Costs	**$ 6,656,204**	Meters and Services
PA PUC Direct Customer Costs less USP	**$ 14,830,147**	Meter Reading
Annual Bills (Customer Count * 12)	659,976	Customer Service
Unit Costs	**$ 22.47**	Billing and Collections

As seen in the above table, the total customer-related costs of $36.9 million result in a monthly Residential customer cost of $55.88. These costs are fixed with respect to the number of customers and do not vary with the amount of energy used or the amount of demand. A total of $36.9 million of Residential customer-related costs are broken down between the customer portion of distribution facilities and customer service and billing costs.

[11] For Total Customer Related Costs See Exhibit D, Schedule 8, line 41, line 67 (annual bills) and Exhibit D, Schedule 7, line 139 (USP Rider Costs). For Distribution Facilities – Customer Portion see Exhibit D, Schedule 8, line 31. For PA PUC Direct Customer Costs see Exhibit D, Schedule 8, line 36.

Q. Can you please discuss the results in Table 6 above within the context of the Company's proposed Residential customer charge of $13.50 and past Commission precedent?

A. Yes, past Commission precedent defines customer-related costs for inclusion in a customer charge as costs associated with meters and services and related Operations and Maintenance ("O&M") expenses, meter reading and billing and collection expenses, meter data management systems, and related employee benefits, administrative and general expenses. The Company is proposing a customer charge of $13.50, which is below the $22.47 within Table 6 above and represents meter reading, customer service, and billing and collection expenses. These are all costs historically allowed by the Commission in a customer charge. Taking into consideration past precedent in Pennsylvania and given the results of the ACOSS as shown in Table 6 above, the Company is proposing to move the Rate R customer charge to $13.50.

Q. What criteria were utilized to determine that a $14.00 customer charge for the General Service rate class is appropriate?

A. The General Service rate class does not have a demand charge, so all distribution margin revenues are recovered through either the monthly customer or the volumetric charge. There were three options to recover the demand-related costs and the costs associated with the minimum distribution system: (1) introduce a demand charge; (2) put all of the increase in the volumetric charge; or (3) recover the demand and costs associated with the minimum distribution system within the monthly customer charge. Introducing a demand charge was not viable given current metering technology, and concerns relating to administrative billing complexity and recovering the demand costs and minimum distribution facilities fully through the customer charge or the volumetric charge did not balance the principles of rate design earlier discussed (e.g., fairness, stability, and consumer rationing/economic efficiency). After reviewing the current level of the customer charge for General Service-4 at $15.00 and the proposed level of Residential at $13.50, it was determined a reasonable middle ground would be to propose a $14.00 monthly customer charge for General Service-1. This allows some of these fixed demand and minimum distribution costs to be recovered through a fixed monthly customer charge rather than a volumetric charge, without introducing a demand charge for the General Service class. This proposed increase to the customer charge results in approximately 27% of the total non-default service revenue for General Service-1 being recovered through the customer charge, which is comparable to the 30% recovered from both the customer charge and the first block of the demand charge for General Service-4.

Q. Please describe why an increase to the customer charge is important.

A. This becomes particularly important when a customer considers different options for the generation portion of the customer's bill, the purchase of an Electric Vehicle, and investments in conservation and energy efficiency, as these decisions are fundamental functions of usage. These decisions can be distorted when non-usage-related fixed costs are collected on a usage basis. Further, without proper price signals, the economic markets that comprise materials, goods, and services that are inputs and outputs to energy products and services are distorted. As such, companies and people cannot make the proper decision to maximize their preferences on allocating their limited resources of time and money. It is economically inefficient when fixed distribution costs are recovered on a usage basis, and customers implement energy efficiency measures reducing their contribution to fixed costs with no corresponding reduction in the fixed costs of providing service.

VII. CONCLUSION

Q. Please summarize your conclusions and recommendations for UGI Electric's ACOSS, class revenues, and rate design.

A. My conclusions and recommendations are as follows:

- The Commission should accept the results of the Company's ACOSS as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system.
- The Commission should accept the results from the Company's ACOSS as a guide to evaluate and set UGI Electric's class revenues and rate design in this proceeding. As noted above, the Commission previously approved the methods employed by UGI Electric's most recent base rate proceeding.
- The Commission should accept the Company's proposed apportionment of revenues to its rate classes because it reasonably balances the various criteria that the Company

considered in the revenue apportionment process and moves classes towards their cost to serve.

- The Commission should approve the rate design proposed by the Company because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT JDT-1

ATRIUM ECONOMICS
CENTERED ON ENERGY

John D. Taylor

Managing Partner

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EDUCATION

M.A., Economics, American University

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

YEARS EXPERIENCE

18

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

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
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility 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 worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

UGI ELECTRIC STATEMENT NO. 7

JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. - Electric Division

Statement No. 7

Direct Testimony of
John F. Wiedmayer, C.D.P.

Topics Addressed: Depreciation

Date: January 27, 2023

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I. INTRODUCTION

Q. Please state your name and address.

A. My name is John F. Wiedmayer. My business address is 1010 Adams Avenue, Audubon, Pennsylvania 19403.

Q. Are you associated with any firm and in what capacity?

A. Yes. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") as Project Manager, Depreciation and Valuation Studies.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since I graduated from college in June 1986.

Q. What is your educational background?

A. I have an AB Engineering degree from Lafayette College and a Master of Business Administration from the Pennsylvania State University.

Q. Do you belong to any professional societies?

A. Yes. I am a member of the National and Pennsylvania Societies of Professional Engineers and the Society of Depreciation Professionals ("SDP"). In 2005, I served as President of the SDP and was a member of the SDP's Executive Board for the years 2003 through 2007.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The SDP has established national standards for depreciation professionals. The SDP administers an examination to become certified in this field. I passed the certification exam in September 1997 and have fulfilled the requirements necessary to remain a Certified Depreciation Professional.

Q. Please outline your experience in the field of depreciation.

A. I have over 36 years of depreciation experience, which includes expert testimony in numerous cases before 14 regulatory commissions, including the Pennsylvania Public Utility Commission ("PA PUC" or the "Commission").

In June 1986, I was employed by Gannett Fleming as a Depreciation Engineer. I held that position from June 1986 through December 1995. In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In August 2004, I was promoted to Project Manager of Depreciation Studies. In 2020, I was promoted to my present position as Senior Project Manager of Depreciation Studies. I am responsible for conducting depreciation and valuation studies, including the preparation of testimony, exhibits, and responses to data requests for submission to the appropriate regulatory bodies. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

During the course of my employment with Gannett Fleming I have assisted in the preparation of numerous depreciation studies for utility companies in various industries such as electric, gas, water, steam, telephone and railroads.

In each of the studies I was involved with, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service lives and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies.

Q. Have you previously testified on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Kentucky Public Service Commission, the Newfoundland and Labrador Board of Commissioners of Public Utilities, the Nova Scotia Utility and Review Board, the Federal Energy Regulatory Commission, the Utah Public Service Commission, the Arizona Corporation Commission, the Missouri Public Service Commission, the Illinois Commerce Commission, the Maine Public Utilities Commission, the Maryland Public Service Commission, the New York Public Service Commission, the New Jersey Board of Public Utilities, Public Utilities Regulatory Authority (for Connecticut) and the PA PUC.

Q. Have you received any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study." In 1999, I became an instructor at the SDP's annual conference lecturing on "Salvage Concepts," "Depreciation Models," "Analyzing the Life of Real-World Utility Property – Actuarial Analysis," "Theoretical Reserve" and "Data Requirements for a Depreciation Study." I am a faculty member of the Society of Depreciation ("Society") and since 1999 have been responsible for preparing and presenting courses on depreciation matters each year at the Society's annual conference.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the electric plant of UGI Utilities, Inc. - Electric Division ("UGI Electric" or the "Company") in this proceeding. I have been retained by the Company as a depreciation consultant. UGI Electric retained me to determine the book depreciation reserve as of September 30, 2024, and to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI Electric's depreciated original cost of electric plant in service included in rate base. My testimony will address my depreciation study, the appropriate depreciation reserve for ratemaking purposes, the original cost measure of value, and the appropriate annual depreciation expense to be included in the ratemaking cost of service as of September 30, 2024.

Q. Were you responsible for the preparation of any of the Company's responses to the Commission's filing regulations that were filed in support of the Company's general rate filing?

A. Yes. I am the responsible witness for the following items in UGI Electric Books I and II:

Item No.	Subject
II-D-13	Experienced and Estimated Net Salvage
V-A-1	Electric Plant in Service
V-A-2	Comparison of Calculated Reserve vs. Book Reserve
V-A-3	Projected Plant and Reserve Balances
V-B-1	Comparison of Calculated vs. Book Accruals
V-B-2	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
V-C-1	Retirement Rate Actuarial Method of Life Analysis
V-D-1	Summary Depreciation Calculations by Account
V-D-2	Detailed Depreciation Calculations by Account and Vintage Year
V-E-1	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account

Q. Have you previously prepared comparable studies for UGI Electric?

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI Electric base rate cases at Docket Nos. R-2017-2640058 and R-2021-3023618. Also, I provided testimony on depreciation matters for the Company in the prior two UGI Penn Natural Gas ("PNG") base rate cases at Docket Nos. R-2016-2580030 and R-2008-2079660, the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket Nos. R-2010-2214415 and R-2008-2079675, and the prior four UGI Utilities, Inc. – Gas Division ("UGI Gas") base rate cases at Docket Nos. R-2021-303-0218, R-2019-3015162, R-2018-3006814 and R-2015-2518438. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's previous base rate case filed in 1995 at Docket No. R-00953297 and UGI Electric's prior two base rate cases at Docket Nos. R-00973975 and R-00953534.

III. OUTLINE OF EXHIBITS C (FULLY PROJECTED FUTURE), C (FUTURE) AND C (HISTORIC)

Q. Will you be sponsoring any exhibits with your direct testimony?

A. Yes, I am attaching and sponsoring the following exhibits: UGI Electric Exhibit C (Fully Projected Future), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Historic). UGI Electric Exhibit C (Fully Projected Future) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2024 ("FPFTY"). UGI Electric Exhibit C (Future) presents summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2023 ("FTY"). UGI Electric Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2022 ("HTY"). Each of the three exhibits is organized in a similar manner and each contains information and schedules supporting the amounts applicable to each test year period. UGI Electric Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Electric Exhibit C (Fully Projected Future) accurately portray the results of your depreciation study as of September 30, 2024?

A. Yes.

Q. In preparing the depreciation study (contained in Exhibit C (Future)), did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Please describe the contents of the depreciation study reports, UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected Future).

A. The depreciation study report in UGI Electric Exhibit C (Future) consists of eight parts, including charts and tables filed in the Company's most recent service life study report submitted to the PA PUC in May 2022 based on electric plant in service as of September 30, 2021. Part I, Introduction, includes statements related to the scope of and basis for the depreciation study. Part II, Estimation of Survivor Curves, presents detailed discussions of: (1) survivor curves; and (2) methods of life analysis including an example of the retirement rate method. Part III, Service Life Considerations, presents the relevant factors considered for estimating service lives. Part IV, Calculation of Annual and Accrued Depreciation, sets forth a description of: (1) the group depreciation procedures used for calculating annual and accrued depreciation; and (2) an explanation of the manner in which net salvage was incorporated in the calculations. Part V, Results of Study, includes a description of the results and summaries of the detailed depreciation calculations as of September 30, 2023. Part VI, Service Life Statistics, presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. Part VII, sets forth the detailed depreciation calculations related to surviving original cost as of September 30, 2023. The detailed depreciation calculations present the annual and accrued depreciation amounts by account and vintage year. The remaining life annual accrual rate is also set forth in the tables of Part VII. Part VIII, Experienced and Estimated Net Salvage, contains the net salvage amortization of experienced and estimated net salvage for the fiscal years 2019 through 2023.

UGI Electric Exhibit C (Fully Projected Future) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2024. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Fully Projected Future). The graphs and tables related to service life presented in UGI Electric Exhibit C (Future) also support the service life estimates used in UGI Electric Exhibit C (Fully Projected Future) and UGI Electric Exhibit C (Historic), since the estimates are the same for all three test years.

The results of the study are set forth in Part II in UGI Electric Exhibit C (Fully Projected Future). Table 1, pages II-3 through II-5 of UGI Electric Exhibit C (Fully Projected Future), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2024, and the calculated annual depreciation rate and amount for each account or subaccount of Electric Plant in Service. Table 2, pages II-6 through II-7 of UGI Electric Exhibit C (Fully Projected Future), presents the bring-forward to September 30, 2024, of the depreciation reserve as of September 30, 2023. Table 3, pages II-8 through II-10 of UGI Electric Exhibit C (Fully Projected Future), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-11 and II-12 of UGI Electric Exhibit C (Fully Projected Future), presents the experienced and estimated net salvage for fiscal years 2020 through 2024. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2019 through September 30, 2024. The summary tables and detailed depreciation calculations set forth in UGI Electric Exhibit C (Fully Projected Future) as of September 30, 2024, are organized and presented in the same manner as those presented in UGI Electric Exhibit C (Future) as of September 30, 2023.

Q. Please outline the contents of Exhibit C (Historic).

A. UGI Electric Exhibit C (Historic) is organized like UGI Electric Exhibit C (Fully Projected Future). UGI Electric Exhibit C (Historic) includes: a description of the scope, basis and results of the studies; summaries of the depreciation calculations; and the detailed depreciation calculations as of September 30, 2022. The descriptions and explanations presented in UGI Electric Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Electric Exhibit C (Historic). The same depreciation methods and procedures used to calculate depreciation were used in all three test year periods. The summary tables and detailed depreciation calculations as of September 30, 2022, are organized and presented in the same manner as those as of September 30, 2024 with two exceptions. Tables 2 and 3 presented in UGI Electric Exhibit C (Fully Projected Future) are not necessary and, therefore, are not presented in UGI Electric Exhibit C (Historic).

IV. <u>THE DEPRECIATION STUDY - OVERVIEW</u>

Q. Please describe what you mean by the term "depreciation."

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act (or, as referenced in Ms. Ressler's testimony, FERC Uniform System of Accounts). "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation, against which the company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.

In the study that I performed, which is the basis for my testimony, I used the straight line remaining life method of depreciation, with the average service life and equal life group procedures. The annual depreciation is based on a system of depreciation accounting that aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of the unit, or group of assets, in a systematic and rational manner.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation and Service Life Study Report filed in May 2022?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used by the Company for many years. The depreciation methods and procedures are described further in Part II of UGI Electric Exhibit C (Future).

For General Plant Accounts 391, 393, 394, 395, 397 and 398, I used the straight line remaining life method of amortization. The annual amortization is based on amortization accounting, which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

V. ORIGINAL COST MEASURE OF VALUE

Q. What is the original cost of electric plant to be included in rate base in this proceeding?

A. As of September 30, 2024, the original cost of electric plant in service is $275,001,657 as shown in column 4 of Table 1 on pages II-3 through II-5 of UGI Electric Exhibit C (Fully Projected Future). This amount includes $253,053,061 of Electric Plant and $21,948,596 of Other Utility Plant allocated to UGI Electric. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used among the gas and electric divisions at UGI Corporation. The costs related to Common Plant and IS are allocated to UGI Electric using specific allocation factors.

Also, the Empire Office and Service Center in Wilkes Barre, PA is a facility jointly used by both UGI utility divisions; however, the cost of the facility is currently included in the gas division for book accounting purposes. For ratemaking purposes, a portion of the Empire facility has been allocated to the electric division.

Also, 25.6247 percent of the UGI Electric Division's Intangible, General and Common Plant were excluded from the Company's current proceeding based on the transmission factor from UGI Electric's most recent transmission rate filing before FERC. The amounts allocated to Transmission Plant and excluded from electric distribution operations are shown on Table 1 of Exhibit C (Fully Projected Future).

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Electric's accrued depreciation for ratemaking purposes as of September 30, 2024?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2024, to be $85,744,907.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over thirty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last proceeding.

Q. How did you determine UGI Electric's allocated book depreciation reserve as of September 30, 2023?

A. The book depreciation reserve allocated to UGI Electric as of September 30, 2023, is set forth in column 5 of Table 1 of UGI Electric Exhibit C (Future). Table 2 of UGI Electric Exhibit C (Future) presents an annual bring-forward of the book depreciation reserve as of September 30, 2022, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2022 through September 2023. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2022, the estimated reserve activity, and the ending reserve balance as of September 30, 2023. The estimated reserve activity consists of depreciation accruals (column 3), amortization of net salvage (column 4), projected retirements (column 5), projected salvage (column 6) and projected cost of removal (column 7). Table 3 of UGI Electric Exhibit C (Future) sets forth the calculation of the estimated depreciation accruals by plant account, which is carried forward to column 3 of Table 2. The book reserve as of September 30, 2022, by plant account, shown in column 2 of Table 2 was obtained from UGI Electric's books and records. The book depreciation reserve as of September 30, 2023 is the sum of the book reserve at the beginning of the fiscal year, September 30, 2022, and the projected 2023 reserve activity.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2023.

A. The depreciation accruals for the twelve months ended September 30, 2023, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2022, to the projected average 2023 plant balance. The average balance for the twelve months ended September 30, 2023, is computed in columns 2 through 6 of Table 3 and is based on the projected additions and retirements in columns 3 and 4.

Q. With reference to Exhibit C (Future) Table 2, column 4, please explain what you mean by "the amortization of net salvage" and explain the manner in which you projected it.

A. The amortization of net salvage is the annual provision for recovering experienced negative net salvage. This process for recognizing net salvage in the cost of service is in accordance with Pennsylvania ratemaking practice. The amortization of net salvage is based on experienced net salvage during the preceding five-year period, October 1, 2018 through September 30, 2023.

Q. Please explain the manner in which you projected retirements, salvage and removal costs that are shown in columns 4, 5 and 6 of Table 2.

A. Retirements were projected, by plant account, by applying the average retirement ratio, expressed as a percent of additions, i.e., 2018 through 2022, to future test year (FTY) additions for most plant accounts. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. All units are retired per books when the age of the vintage reaches the amortization period. Therefore, all vintages that reached or exceeded the amortization period were retired during the FTY for certain General Plant accounts subject to amortization accounting. Salvage and removal costs were projected by plant account by applying the average salvage and cost of removal ratios to the projected retirement amounts. The salvage and cost of removal ratios were determined as an average percent of the retirement amounts recorded for the five years 2018 through 2022.

Q. Was the book reserve at September 30, 2024, estimated using the same methodology?

A. Yes, essentially the same methodology was used with one minor exception. The book depreciation accruals for fiscal year 2024 were calculated by applying depreciation rates established as of September 30, 2023 to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2024.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Electric's annual depreciation expense to be included as an element in the cost of service for purposes of this proceeding?

A. Yes, I have. The annual depreciation expense is $9.074,543 and consists of $8,217,505 of annual accruals to recover original cost and $857,038 of net salvage amortization. The $8,217,505 related to original cost recovery is comprised of two parts, $6,807,498 related to electric plant and $1,410,007 related to Other Utility Plant allocated to UGI Electric. These amounts are set forth in column 8 of Table 1 in UGI Electric Exhibit C (Fully Projected Future).

Q. How did you determine the annual accruals of $8,217,505?

A. The determination of annual depreciation accruals consists of two phases. In the first phase, survivor curves are estimated for each plant account or subaccount. In the second phase, the composite remaining lives and annual depreciation accruals are calculated based on the service life estimates determined in the first phase.

The determination of annual amortization amounts consists of the selection of amortization periods and the calculation of amortization amounts based on the remaining amortization period and the unrecovered cost for each vintage.

Q. Please describe the manner in which you estimated the service life characteristics for each depreciable group in the first phase of the study.

A. The service life study consisted of: compiling historical data from records related to UGI Electric's electric plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI Electric's practices and plans as they relate to plant operations; and interpreting the above data to form judgments of average service life characteristics.

Q. What historical data did you analyze to estimate the service life characteristics of UGI Electric's electric plant?

A. The data consisted of the entries made by UGI Electric to record electric plant transactions during the period 1960 through 2021. The transactions included additions, retirements, transfers, acquisitions, and the related balances. I classified the data by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed.

Q. What method did you use to analyze these service life data?

A. I used the retirement rate method of life analysis. The retirement rate method is the most appropriate when aged retirement data are available because it develops the average rates of retirement actually experienced during the period of study. Other methods of life analysis infer the rates of retirement based on a selected type of survivor curve.

Q. Please describe the results of your use of the retirement rate method.

A. Each retirement rate analysis resulted in a life table, which, when plotted, formed an original survivor curve. Each original survivor curve, as plotted from the life table, represents the average survivor pattern experienced by the several vintage groups during the experience band studied. Inasmuch as this survivor pattern does not necessarily describe the life characteristics of the property group, interpretation of the original curves is required in order to use them as valid considerations in service life estimation. Iowa type survivor curves were used for the purposes of developing these analyses. The results of the retirement rate analyses are presented in Part VI of UGI Electric Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you used it in estimating service life characteristics for each depreciable group.

A. The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type survivor curves. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. Iowa curves are the accepted survivor curves for Pennsylvania, and the remaining 49 other states, and have been for many years.

Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the qualitative outlook for future retirements.

The estimated survivor curve designations for each depreciable group indicate the average service life, the family within the Iowa system and the relative height of the mode. For example, the Iowa 36-R2.5 curve indicates an average service life of thirty-six years; a Right-skewed, or R2.5, type curve (the mode occurs after average life for right modal curves); and a relatively medium height, 2.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. Did you physically observe plant and equipment in the field?

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the Company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the PA PUC every five years, at minimum. UGI Electric's most recent service life study report was submitted in May 2022 based on electric plant in service as of September 30, 2021. Facilities visited during field trips, generally include representative substations, service centers, warehouses, and office buildings. The most recent field trip was conducted in December 2021. The specific dates and locations visited during recent field trips are listed in Exhibit C (Future) in Part III. A general understanding of the function of the plant and information with respect to the reasons for past retirements and expected causes of retirements are obtained during these field trips. This knowledge and information was incorporated in the interpretation and extrapolation of the statistical life analyses.

Q. Please describe the second phase of the process that you used to determine annual depreciation for ratemaking purposes.

A. After I estimated the service life characteristics for each depreciable group, I calculated annual depreciation accruals for each group in accordance with the straight line remaining life method, using remaining lives consistent with the average service life procedure for plant installed prior to 1982 and remaining lives consistent with the equal life group procedure for plant installed in 1982 and subsequent years. Summary tabulations of the survivor curve estimates and the annual accrual rates and amounts are set forth in Table 1 of UGI Electric Exhibit C (Historic), UGI Electric Exhibit C (Future) and UGI Electric Exhibit C (Fully Projected Future). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected Future) and Part VII of UGI Electric Exhibit C (Future).

Q. Please describe briefly the straight line remaining life method of depreciation that you used for depreciable property.

A. The straight line remaining life method of depreciation allocates the original cost less accumulated depreciation in equal amounts to each year of remaining service life for each vintage.

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1982.

A. In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated survivor curve.

Q. Please describe briefly the equal life group procedure that you used in conjunction with the straight line remaining life method for plant installed in 1982 and in later years.

A. In the equal life group procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the composite remaining life for the surviving original cost of that vintage. The composite remaining life for the vintage is derived by weighting the individual equal life group remaining lives. In the equal life group procedure, the property group is subdivided according to service life. That is, each equal life group includes the portion of the property that experiences the life of that specific group. The relative size of each equal life group is determined from the property's life dispersion curve.

Q. Please describe briefly the amortization of certain General Plant accounts.

A. General Plant Accounts 391, 393, 394, 395, 397 and 398 include a very large number of units but represent a small percent of depreciable electric plant. Depreciation accounting is difficult for these assets, inasmuch as periodic inventories are required to properly reflect plant in service. Many utilities have changed to amortization accounting for general plant as a practical and reasonable solution that avoids significant accounting expenditures for such a small percent of plant.

In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. That is, there is no dispersion of retirement for accounts being amortized. All units are retired per books when the age of the vintage reaches the amortization period. Amortization accounting was initiated for UGI Electric in Docket No. R-00932862.

VIII. ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE

Q. Please illustrate the procedure followed in your depreciation study and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 368.1, Transformers, to illustrate the manner in which the study was conducted. Account 368.1 represents approximately 8.3 percent of the total depreciable distribution plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1960 through 2021. These data were coded in the course of UGI Electric's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The plant additions, retirements, and other plant transactions were analyzed by the retirement rate method of life analysis.

This account includes equipment used to reduce electric voltages, primarily pole-top or pad mounted line transformers. Retirements of line transformers are primarily caused by storm damage, deterioration, fire or third-party damage, capacity or loading issues, etc. Discussions with operating and management personnel indicated that the life characteristics of transformers will be similar in the future as they were in the past. Typical service lives for line transformers of other electric companies range from 35 to 45 years.

The life analysis was performed, and the Iowa 45-S1 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The survivor curve estimate used in the previous service life study was the Iowa 43-S1 survivor curve. The Iowa 45-S1 survivor curve is a good fit for the original curve based on the Company's retirement experience for the period 1960-2021. The proposed 45-S1 survivor curve is within the range of estimates used by other electric companies and is consistent with the outlook of Company management. The original and smooth survivor curves are plotted in Part VI on page VI-21 of UGI Electric Exhibit C (Future). The original life table for the 1960-2021 experience band is set forth on pages VI-22 through VI-25.

The calculation of annual depreciation, the second phase, for the original cost of line transformers in service at September 30, 2023, is presented by vintage in Part VII on pages VII-16 through VII-17 of UGI Electric Exhibit C (Future) for Electric Plant in Service. The detailed depreciation calculations at September 30, 2024, are presented in Part III of Exhibit C (Fully Projected Future). The tabular presentations of the detailed depreciation calculations in Part VII of Exhibit C (Future) are similar in kind to those set forth in Part III of Exhibit C (Fully Projected Future). The expectancy and average life derived from the estimated survivor curve for each vintage were used to calculate the accrued depreciation by the average service life procedure for 1981 and prior vintages.

The accrued depreciation for vintages subsequent to 1981 was calculated by the equal life group procedure using the Iowa 45-S1 survivor curve. In the calculation, the surviving cost in each vintage was further subdivided, through the use of a computer program, into depreciable groups according to the expected service lives as defined by the Iowa 45-S1 survivor curve. The accrued depreciation was derived for each equal life group, based on its service life, and the totals shown for the vintages are the summations of the individually derived amounts.

The book reserve was allocated to vintages based on the calculated accrued depreciation. The remaining lives of the vintages were based on the Iowa 45-S1 survivor curve, the attained age, and the same group procedures as were used to calculate accrued depreciation. The future book accruals (original cost less allocated book reserve) were divided by the remaining lives to derive the annual depreciation accruals by vintage.

The total depreciation accrual on page VII-17 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 4 to calculate the annual depreciation accrual rate in column 7. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 368.1 typical of that followed for most of the plant investment?

A. Yes, it is, since the straight-line method and the average service life and the equal life group procedures were used for most of the depreciable plant.

Q. Please illustrate the procedure followed for the amortization of certain General Plant accounts and the manner in which it is presented in UGI Electric Exhibit C (Future) using an account as an example.

A. I will use Account 394, Tools, Shop and Garage Equipment, to illustrate the amortization procedure. As the initial step of the amortization procedure, an amortization period of 20 years was selected based on the period during which such equipment renders most of its service, the amortization periods used by other utilities, and the service life estimate previously used for depreciation accounting.

The calculation of the annual amortization as of September 30, 2023, is presented by vintage in Part VII on page VII-44 of UGI Electric Exhibit C (Future). The calculated accrued amortization is based on the ratio of the vintage's age to the amortization period. The book reserve for vintages older than the amortization period was set equal to the original cost. The remaining book reserve was allocated to vintages based on the calculated accrued depreciation. The future book accruals or amortizations (original cost less assigned or allocated book reserve) were divided by the remaining amortization period to derive the annual amortizations by vintage.

The total amortization on page VII-44 of UGI Electric Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-4 of UGI Electric Exhibit C (Future). A similar process was performed for UGI Electric Exhibit C (Fully Projected Future) and UGI Electric Exhibit C (Historic). That is, the calculation of the annual amortization related to the original cost of Tools, Shop and Garage Equipment in service at September 30, 2024, is presented by vintage on page III-46 of UGI Electric Exhibit C (Fully Projected Future) and summarized in Table 1 on page II-3.

Q. Briefly explain the methods used for the remaining portion of the depreciable plant.

A. The life span procedure was applied to major structures in Account 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI Electric Exhibit C (Historic) and UGI Electric Exhibit C (Fully Projected Future) and in Part VII of UGI Electric Exhibit C (Future).

IX. <u>THE NET SALVAGE AMORTIZATION CLAIM</u>

Q. Please briefly describe the accounting treatment regarding net salvage for public utilities operating in Pennsylvania.

A. In accordance with the Uniform System of Accounts and the rules for recovery of net salvage established by the Pennsylvania Superior Court in *Penn Sheraton Hotel v. Pa. P.U.C.*, 198 Pa. Super. 618, 184 A.2d 324 (1962) ("*Penn Sheraton*"), net salvage is charged to the depreciation reserve and is amortized over a five-year period beginning with the year after net salvage is actually incurred. These accounting procedures were affirmed by the Commission in PPL Gas Utilities Corporation's ("PPL Gas") most recent rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the Company's Annual Depreciation Reports submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI Electric's annual depreciation expense consists, in part, of $857,038 of net salvage amortization. How did you determine that amount?

A. The $857,038 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2019 through September 30, 2024. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most electric utilities, including UGI Electric, cost of removal exceeds gross salvage resulting in negative net salvage. Negative net salvage is recorded to the depreciation reserve as a debit, which reduces the depreciation reserve. Charges related to the negative net salvage amortization are recorded to the depreciation reserve as a credit in the five years subsequent to the initial recording of the negative net salvage amount. Therefore, the negative net salvage amount will have been fully amortized after five years and the net effect on the depreciation reserve is zero. Detailed data related to the experienced and estimated cost of removal and salvage are presented in Part VIII of UGI Electric Exhibit C (Future) and Part IV of UGI Electric Exhibit C (Fully Projected Future).

Q. Do you have any other comments on the other items which you are sponsoring in this proceeding?

A. Yes. The above testimony does not describe the responses to filing requirements set forth in Items V-A-2, V-B-1 and V-B-2. In general, these responses are self-explanatory. The response to V-A-2 is a comparison of the actual and projected book depreciation reserves with the calculated accrued depreciation as of the end of the test years. The response to V-B-1 is a comparison of the calculated depreciation accruals and the book depreciation accruals related to the future and fully projected future test years. The response to V-B-2 presents the survivor curves used in the most recent prior general rate proceeding and the annual accrual rates that resulted from the use of these curves.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC STATEMENT NO. 8

DARIN T. ESPIGH

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 8

Direct Testimony of
Darin T. Espigh

Topics Addressed: **Taxes and Tax Adjustments**

Dated: January 27, 2023

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

A. My name is Darin T. Espigh. My business address is One UGI Drive, Denver, Pennsylvania 17517.

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

A. I am employed by UGI Corporation ("UGI Corp.") as Senior Manager Natural Gas Tax Accounting. UGI Corp. is the parent company of UGI Utilities, Inc. ("UGI"). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your principal duties and responsibilities as Senior Manager Natural Gas Tax Accounting for UGI Corp.?

A. My primary duties as Senior Manager Natural Gas Tax Accounting include the preparation of tax data to be reported in UGI Corp.'s various United States Securities and Exchange Commission and regulatory filings, as well as its various federal and state income and non-income tax return related filings. Additionally, I maintain the current and deferred income tax accrual and expense accounts, perform tax research, and assist UGI with tax matters as they arise. I also manage the reporting of UGI's various tax filings with its local, state, and federal jurisdictions.

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Electric Exhibit DTE-1.

Q. Please describe the purpose of your testimony.

A. I am providing testimony on behalf of UGI Electric. I will explain the Company's *pro forma* tax adjustments to its principal accounting exhibits for the fully projected future test year ending September 30, 2024 ("FPFTY"). I will also explain the tax adjustments made to the results of UGI Electric's historic test year ended September 30, 2022 ("HTY") and future test year ending September 30, 2023 ("FTY").

Q. Mr. Espigh, are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring UGI Electric Exhibits DTE-1, DTE-2, and DTE-3. Together with other Company witnesses, I am sponsoring portions of UGI Electric Exhibit A (Fully Projected), UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) that pertain to taxes. These exhibits comprise UGI Electric's principal accounting exhibits for the HTY, FTY, and FPFTY. I am also sponsoring certain responses to the Commission's filing requirements and standard data requests. Each response identifies the witness sponsoring it.

II. <u>TAX ADJUSTMENTS</u>

Q. Please provide an overview of UGI Electric's principal accounting exhibits relative to the proposed tax adjustments.

A. As explained in the direct testimony of Tracy A. Hazenstab (UGI Electric Statement No. 2), UGI Electric's principal accounting exhibit is UGI Electric Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Electric Exhibit A (Fully Projected) presents necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to taxes are summarized in Schedules D-31 through D-34. These tax adjustments are used to derive UGI Electric's *pro forma* income at present and proposed rates as set forth in Schedule A-1 of the same exhibit.

UGI Electric Exhibit A (Future) and UGI Electric Exhibit A (Historic) follow the format of UGI Electric Exhibit A (Fully Projected), but reflect data for the HTY, and the FTY. This information is provided in accordance with the Commission's filing requirements and provides a basis for comparing UGI Electric's FPFTY claims with actual book results from the HTY and adjusted FTY results. Section D to UGI Electric Exhibit A (Historic), Schedule D-31, and UGI Electric Exhibit A (Future), Schedule D-31 include adjustments that share the same methodology as used in Schedule D-31 of UGI Electric Exhibit A (Fully Projected).

A. TAXES OTHER THAN INCOME TAXES

Q. How was the provision for taxes-other-than-income taxes ("TOTI") determined for the FPFTY?

A. TOTI consists of the Pennsylvania Utility Realty Tax ("PURTA"), the Pennsylvania Gross Receipts Tax, Pennsylvania and Local Use taxes, Social Security taxes, Federal Unemployment tax ("FUTA"), State Unemployment tax ("SUTA") and the Company's assessed contribution to the budgets of the Commission, the Pennsylvania Office of Consumer Advocate, and Pennsylvania Office of Small Business Advocate. TOTI amounts were based on the plan year budget, as adjusted for reasonably known and measurable changes to various payroll taxes as explained by the direct testimony of Ms. Hazenstab (UGI Electric Statement No. 2). The adjustments are shown on UGI Electric Exhibit A (Fully Projected), Schedule D-31. The net adjustment of $0.180 million is brought forward to Schedule D-3, page 2.

B. INCOME TAXES

Q. Please discuss the Company's claim for income taxes.

A. Income tax expense for the FPFTY at present and proposed rates is set forth in UGI Electric Exhibit A (Fully Projected), Schedule D-33. Income taxes are calculated using the procedures normally followed by the Commission, including the use of debt interest synchronization, the normalization method for accelerated depreciation used in the calculation of federal income taxes, and the flow-through of accelerated depreciation benefits for state tax purposes. UGI Electric is continuing its practice of normalizing the tax repairs expense deduction for federal tax purposes. For state tax purposes, UGI Electric continues to flow-through the repairs tax benefit over the tax lives of the asset that generated the benefit, which is generally 20 years. The fully adjusted claim for the FPFTY income tax expense is shown on UGI Electric Exhibit A (Fully Projected), Schedule D-1.

Q. Please describe the claim for income taxes shown on Schedule D-1, lines 18 and 19.

A. The calculation of federal and state income taxes can be found on Schedule D-33, lines 13 and 19. This schedule shows the calculation of *pro forma* income taxes for the FPFTY at present and proposed rates. Line 1 shows the revenue at present and proposed rates, while line 2 shows the operating expenses at present and proposed rates from Schedule D-1. Line 3 reflects operating income before debt interest is deducted, by netting line 1 from line 2. Debt interest expense is synchronized by multiplying the rate base claim from Schedule C-1 by the weighted cost of debt recommended in the direct testimony of Paul R. Moul (UGI Electric Statement No. 9) and shown on Schedule B-7. The resulting interest expense on line 6 is subtracted from net income before debt interest to calculate base taxable income on line 7.

In accordance with established Commission practice, lines 8 through 11 of Schedule D-33 reduce the base taxable income, for state tax purposes, by the total difference between accelerated tax depreciation shown on line 8 and the *pro forma* book depreciation shown on line 9. The statutory state corporate net income tax rate was then applied (as further described below in Section F of my testimony) to determine the *pro forma* state income tax expense shown on line 13. Lines 14 through 19 show the federal income tax expense calculation at current and proposed rates, while line 20 sums the state and federal tax expense amounts before application of Deferred Federal and State Income Taxes. At lines 21 through 28, Deferred Federal and State Income Taxes are used to increase the *pro forma* income tax expense at present and proposed rates with the total calculated amount for income taxes before the application of other adjustments shown on line 29. The amounts of accelerated depreciation, cost of removal, repairs tax deduction, tax basis adjustments to plant, straight line depreciation and book depreciation used in the determination of income taxes are summarized on Schedule D-34.

Q. What is the total FPFTY income tax expense for UGI Electric?

A. As shown on Schedule D-33 at line 31, the *pro forma* tax expense at present rates is $0.669 million and the *pro forma* tax expense at proposed rates for the FPFTY is $3.770 million. As explained below in Section E of my testimony, this figure is not reduced by a consolidated income tax adjustment.

Q. Did the Company reflect the amortization of Excess Deferred Federal Income Taxes ("EDFIT") resulting from the 2017 Tax Cuts and Jobs Act ("TCJA") in its income tax expense claim?

A. Yes, the Company calculated the amount of the EDFIT to be amortized and flowed back to ratepayers in its FPFTY. This amount is included in the overall federal deferred tax expense calculated on Line 25 of Schedule D-33. The total amortization was approximately $0.283 million, calculated using the Average Rate Assumption Method ("ARAM") as required by tax normalization rules.

C. ACCUMULATED DEFERRED INCOME TAXES

Q. How are Accumulated Deferred Income Taxes ("ADIT") calculated?

A. Schedule C-6 shows the FPFTY ending balance for federal ADIT at September 30, 2024. This amount is deducted from rate base. The total shown on line 8 reflects the difference in income tax expense for book and tax purposes attributable to the difference between the accelerated tax depreciation and straight-line book depreciation on test year plant balances, net of offsets associated with contributions in aid of construction. Rate base was reduced further by the state regulatory liability associated with UGI Electric's repairs tax method shown on line 6. As the state tax consequence of accelerated depreciation is flowed through, there is no associated state ADIT balance.

Q. What is the amount of the ADIT offset to rate base?

A. As shown on line 8 of Schedule C-6 and on line 5 of Schedule A-1, the ADIT offset is $29.665 million, which includes an amount related to the repairs tax method explained below in Section D of my testimony.

Q. Does the Company's reduction to rate base include an amount associated with EDFIT?

A. Yes, the Company reduced its rate base by the unamortized EDFIT, which is incorporated in the ADIT balance on Line 8 of Schedule C-6.

Q. Did the Company calculate its federal ADIT rate base deduction in compliance with the normalization requirements of the Internal Revenue Code?

A. Yes. The Company's calculation properly reflects the pro-rationing concept in accordance with Treasury Regulation 1.167(l)-1(h)(6)(ii) that it must follow for ratemaking purposes to comply with IRS normalization requirements. To qualify for normalization, the IRS requires utilities to pro-rate rate base deductions for ADIT to account for the fact that the Company accrues ADIT for plant additions throughout the year. See UGI Electric Exhibit DTE-2 for the calculation of the pro-rata adjustment.

D. REPAIRS TAX METHOD

Q. Please explain UGI Electric's accounting treatment of the Repairs Tax Method.

A. In its tax return for the year ended September 30, 2009, UGI Electric adopted a tax accounting method to expense as repairs certain items capitalized for book purposes in accordance with federal tax regulations. As it did in the Company's previous base rate case at Docket No. R-2021-3023618, UGI Electric chose to normalize its federal income tax expense claim, inclusive of the repairs tax deduction. This difference between accelerated tax depreciation versus book depreciation in the calculation of federal tax expense creates ADIT. For state income tax purposes, solely with respect to the repairs tax deduction, UGI Electric chose to flow-through the repairs tax benefit over the tax useful lives of the assets generating the tax deduction. The state ADIT balance associated with the repairs tax deduction is classified as a regulatory liability, as it represents the repairs tax benefit that ratepayers have not yet received. In both the federal and state instances, the ADIT balance amortizes or unwinds over the remaining life of the asset.

As noted previously, the Company reduces rate base by the sum of the federal ADIT balance and the state repair regulatory liability.

E. CONSOLIDATED TAX BENEFITS

Q. Does the Company's proposed revenue requirement reflect a consolidated tax expense adjustment?

A. No. The Company's revenue requirement is established based on its stand-alone federal income tax attributes. It is my understanding that Act 40 of 2016, which added 66 Pa. C.S § 1301.1 to the Public Utility Code, eliminates the need to show a consolidated tax adjustment for ratemaking purposes. However, Section 1301.1(b) requires a public utility to demonstrate that it shall use at least 50 percent of what would have been a consolidated tax expense adjustment under the law prior to Act 40 for reliability or infrastructure related capital investment and the other 50 percent shall be used for general corporate purposes.

A calculation of such an adjustment for that purpose, using the modified effective tax rate methodology traditionally used by the Commission prior to the enactment of Act 40, is included in the Company's filing as UGI Electric Exhibit DTE-3. Company witness Ms. Tracy A. Hazenstab (UGI Electric Statement No. 2) discusses how the Company has satisfied the requirements of Act 40.

F. PENNSYLVANIA TAX RATE CHANGE

Q. Are you familiar with the recently enacted Pennsylvania tax rate change?

A. Yes. On July 8, 2022, Governor Wolf signed into law Act 53, which will reduce the state corporate net income tax rate from the current 9.99% to 4.99% over a nine-year period. The initial reduction to 8.99% is effective for tax years beginning in calendar year 2023. Thus, the initial reduction applies to Fiscal Year End September 30, 2024, which is the Company's FPFTY.

Q. How has the Company accounted for the recently enacted Pennsylvania tax rate change?

The Company's claim for income taxes reflects the applicable state tax rate in effect for the HTY (i.e., 9.99%), FTY (i.e., 9.99%) and FPFTY (i.e., 8.99%). As explained above, the initial reduction applies to our FPFTY. The State Tax Adjustment Surcharge ("STAS") mechanism will adjust the Company's rates as applicable for future reductions to the state tax rate.

Q. How is the Company applying the Pennsylvania tax rate change to its Repairs Tax method?

A. Consistent with historic treatment as described in Section D of this testimony, UGI Electric's state regulatory liability associated with its repairs tax method will continue to represent the tax benefit, based on the rate in effect, that ratepayers have not yet received.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI ELECTRIC

EXHIBIT DTE-1

DARIN ESPIGH, CPA

PROFESSIONAL EXPERIENCE

UGI UTILITIES, INC., Denver, PA — ***March 2022 - Present***
Senior Manager of Natural Gas Tax Accounting

Manage the accounting for income taxes in accordance with ASC 740 for Natural Gas business segment. Provide technical accounting guidance and expertise on tax accounting, planning and compliance matters. Oversee and review the preparation of information supporting various regulatory filings. Oversee and review the preparation of various tax related filings. Supervise 2 direct reports.

JBS USA, Greeley, CO — ***2014 – March 2022***
Senior Tax Manager, Tax Accounting and Global Reporting

Manage tax accounting and reporting under ASC 740 including effective rate development, perm development, valuation allowances, ABP 23 indefinite reinvestment assertions, financial statement footnotes, management of global deferred inventory and FIN48/FAS 5 analysis for international consolidated financial statements. Responsible for IFRS adjustments and reporting package to Brazilian parent company. Interface with internal and external auditors. Managed tax accounting aspects of a large global reorganization. Design and streamline provision reporting packages to meet increased demands of public reporting.

Managed both federal and state income tax compliance. Responsible for attribution memos related to the preparation of Form 5472, R&D Credits, Sec 163(j), Schedule G and Schedule O compliance for more than 10 separate federal tax returns. Supervised income tax audits. Managed documentation and notice requirements related to the Foreign Investment in Real Property Tax Act (FIRPTA) related to distributions of U.S. real property interests by foreign corporations. Managed, trained and developed staff in tax accounting and financial reporting and compliance.

UGI UTILITIES, INC., Reading, PA — ***2007 to 2014***
Senior Tax Analyst

Responsible for quarterly and annual tax accounting and reporting under ASC 740 including effective rate development, maintenance and classification of deferred inventory balances and account reconciliations. Calculate annual provision to return adjustment for year-end provision. Interface with internal and external auditors on tax related matters. Provide budget and forecast amounts for all tax related items. Preparation of tax data to support external regulatory reporting including Base Rate Case filings.

Preparation of income tax return support submitted to corporate for inclusion in the consolidated income tax return. Responsible for indirect tax compliance.

BERTZ & COMPANY, CPA's, Lancaster, PA — ***2000 to 2007***
Senior Associate

Responsible for preparation of individual, corporate, partnership, nonprofit and payroll tax returns. Charged with the preparation of financial statements including required disclosures for a wide range of industries including construction, hospitality and retail food establishments. Supervised, trained and developed staff on client engagements.

DARIN ESPIGH, CPA

Managed audit engagements of retirement plans and homeowner associations. Gained experience on a variety of other audits.

HATTER, HARRIS & BEITTEL, LLP, Lancaster, PA — ***1994 to 2000***
Senior Associate

Prepared individual, corporate, partnership, nonprofit and payroll tax returns. Managed review and compilation engagements. Managed nonprofit audit. Developed significant experience in audits of school districts, retail and manufacturing businesses. Gained strong working knowledge of financial statements and related disclosures for engagements of all levels. Trained and developed new staff.

EDUCATION & CREDENTIALS

Bachelor of Science in Accounting – Messiah College, Grantham, PA – May 1994

Certified Public Accountant

UGI ELECTRIC

EXHIBIT DTE-2

UGI - Electric Division
Calculation of Pro-Rata Accumulated Deferred Income Tax
(In Thousands)

	A	B	C = B/365	D = C*A	Per Treas. Reg.1.167(l)-1(h)(6)(ii)
Month	Increase to Deferred Taxes	# of Days	Pro-Rata %	Pro-Rata Incr to Deferred Taxes	Accumulated Deferred Income Tax Balance
9/30/2023					$ 29,114
10/31/2023	107	335	91.78%	98	29,212
11/30/2023	173	305	83.56%	144	29,356
12/31/2023	68	274	75.07%	51	29,407
1/31/2024	44	243	66.58%	29	29,436
2/28/2024	131	215	58.90%	77	29,513
3/31/2024	62	184	50.41%	31	29,544
4/30/2024	86	154	42.19%	36	29,581
5/31/2024	59	123	33.70%	20	29,600
6/30/2024	111	93	25.48%	28	29,629
7/31/2024	123	62	16.99%	21	29,650
8/31/2024	142	31	8.49%	12	29,662
9/30/2024	1,035	1	0.27%	3	**$ 29,665**

UGI ELECTRIC

EXHIBIT DTE-3

UGI Utilities, Inc. - Electric Division
Calculation of Consolidated Tax Adjustment
In Thousands (000)

		Taxable Income 2019	Taxable Income 2020	Taxable Income 2021	Average	
Tax Loss Entities						
AmeriGas Propane Holdings, Inc.		0	0		0	
Ashtola Production Company		(1)	(1)	(1)	(1)	
Hellertown Pipeline		0	0	0	0	
Homestead Holding		(273)	(607)	(76)	(319)	
Mountaineer Energy Holding & Subs	A/	0	0	0	0	
UGI Hunlock Dev		0	0	0	0	
UGI HVAC Enterprises		(305)	0	(1,556)	(620)	
UGI LNG		0	0	(3,679)	(1,226)	
UGID Holding Company		(8)	(8)	(8)	(8)	
United Valley Insurance		(751)	0	0	(250)	
UGI Corporation	A/	0	(11,911)		(3,970)	
AmeriGas Inc		(26)	(23)	0	(16)	
UGI China Inc		0	0	0	0	
UGI International China. Inc		0	0	0	0	
UGI Penn HVAC Services		0	0	0	0	
UGI Properties, Inc.		0	0	0	0	
UGI Development Company	A/	(5,924)	(4,961)	(4,031)	(4,972)	
UGI Enterprises Inc		0	0	0	0	
Subtotal Taxable Loss		**(7,286)**	**(17,511)**	**(9,351)**	**(11,383)**	
Tax Positive Entities						% of Total
AmeriGas Propane Inc.		93,880	56,320	30,085	60,095	25.4%
AmeriGas Propane Holdings, Inc.	A/	90	0	122,728	40,939	17.3%
AmeriGas Inc.		0	0	178	59	0.0%
Amerigas Technology Group Inc.		0	0	0	0	0.0%
Energy Service Funding		5,062	3,479	4,656	4,399	1.9%
Newberry Holding		3,253	955	120	1,443	0.6%
Petrolane Incorporated		0	0	0	0	0.0%
UGI China, Inc.		0	0	0	0	0.0%
UGI Corporation	A/	44,119	0	23,110	22,410	9.5%
UGI Development Company		0	0	0	0	0.0%
UGI Enterprises, Inc.		0	0	0	0	0.0%
UGI Europe, Inc.		35,767	22,795	42,637	33,733	14.2%
UGI HVAC Enterprises		0	4,824	0	1,608	0.7%
UGI LNG		5,530	2,318	0	2,616	1.1%
UGI Penn HVAC Services		3	0	0	1	0.0%
UGI Properties, Inc.		245	349	438	344	0.1%
UGI Storage Company		4,465	4,152	4,997	4,538	1.9%
UGI Utilities, Inc.		57,929	73,276	62,490	64,565	27.3%
UGI International Enterprises, Inc.		0	0	0	0	0.0%
United Valley Insurance		0	323	146	156	0.1%
Eliminations		0	0	0	0	0.0%
Subtotal Taxable Income		**250,343**	**168,792**	**291,584**	**236,906**	100.0%
Total Taxable Income		**243,056**	**151,281**	**282,233**	**225,523**	

Tax Savings Applicable to UGI Utilities, Inc.	(3,102)
MWF Allocation % for UGI Utilities - Electric Division	10.71%
Federal Tax Rate	21%
Total Consolidated Tax Adjustment	**(70)**

A/ Taxable income / loss is adjusted for unusual, non-recurring items and for expenses incurred related to the generation of income in other entities.

UGI ELECTRIC STATEMENT NO. 9

PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 9

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

Topics Addressed:	**Capital Structure**
	Cost of Equity
	Rate of Return

Dated: January 27, 2023

UGI Utilities, Inc. – Electric Division
Direct Testimony of Paul R. Moul
Table of Contents

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CWIP	Construction Work in Progress
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
Lev	Leverage modification
LT	Long Term
P-E	Price-earnings
PUC	Pennsylvania Public Utility Commission
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
s x v	Represents external growth
S&P	Standard & Poor's
UGIU	UGI Utilities, Inc.
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in UGI Electric Exhibit PRM-1, which follows my direct testimony.

Q. What is the purpose of your testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PUC" or the "Commission") should recognize in the determination of the revenues that UGI Utilities, Inc. – Electric Division ("UGI Electric" or the "Company") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in UGI Exhibit B, which is a multi-page document divided into fourteen (14) schedules. All references to schedules in my testimony refer to portions of UGI Electric Exhibit B.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company?

A. My conclusion is that the Company should be afforded an opportunity to earn a cost of equity of 11.30%. The 11.30% rate of return on common equity includes 20 basis points in recognition of the strong performance of the Company's management. My 11.30% cost of equity recommendation is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company.

My overall rate of return recommendation is determined by using the weighted average cost of capital approach. This approach provides a means to apportion the return to each class of investor. The calculation of the weighted average cost of capital requires the selection of appropriate capital structure ratios and a determination of the cost rate for each capital component. The resulting overall cost of capital when applied to the Company's rate base will provide a level of return that will compensate investors for the use of their capital. My overall cost of capital recommendation is set forth below and is shown on page 1 of Schedule 1.

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-term Debt	45.41%	4.35%	1.98%
Common Equity	54.59%	11.30%	6.17%
Total	100.00%		8.15%

This overall rate of return is applicable to the September 30, 2024 fully projected future test year ("FPFTY") and the initial period that the Company's proposed rates will be effective. The direct testimony of Company witness Christopher R. Brown, VP and General Manager of Rates and Supply (UGI Electric Statement No. 1), explains that the Company has achieved a high level of management effectiveness and is entitled to recognition of this as a component of the rate of return on common equity. Therefore, an additional 0.20% is warranted in recognition of the strong performance by the Company in the area of management effectiveness.

Q. What noteworthy factors have influenced your cost of equity analysis?

A. My cost of equity analysis reflects the high levels of inflation which have not been seen for four decades. Indeed, the rate of inflation spiked upward to 9.1% in June 2022, and as of December 2022, it was 6.5%. High levels of inflation have an impact on the level of economic activity, the cost of capital – particularly the interest cost of debt – and the need for more cautious financial practices, such as a prudent level of borrowing. This is substantially higher than the target rate of 2%, which is the FOMC policy goal.

Contributing to "sky high" inflation is pandemic-related supply side issues, strong consumer demand, and tight labor markets. Supply disruptions have also significantly impacted the consumer sector of the economy, which developed during the Pandemic. Energy prices have increased as well. While short-term interest rates were at historically low levels during much of the Pandemic, longer term interest rates began to rise in February 2021 and have continued at high levels throughout 2022. Moreover, the first of several Fed Funds increases was announced on March 16, 2022, with an increase of 0.25%, and an additional 0.50% increase was announced on May 4, 2022. A 50 basis point increase in the Fed Funds rate has not occurred since 2000. Indeed, the Fed Funds rate was increased again with the announcement on June 15, 2022, when a 0.75% increase occurred. Additional 0.75% increases in the Fed Funds rate were announced on July 27, 2022, September 21, 2022, and November 2, 2022. This makes four consecutive three-quarter percentage point increases in the Fed Funds rate, which is unprecedented in recent history. Subsequently, at its December 14, 2022 meeting, the FOMC increased the Fed Funds rate by 0.50% to a level of 4-1/4 to 4-1/2 percent, a fifteen (15) year high. In total, the Fed Funds rate has been increased 425 basis points in 2022. The FOMC is projecting the Fed Funds rate will peak at a level between 5% and 5.5% in 2023. That level is expected to hold there until sometime in 2024. I will describe the forecasts of interest rates later in my testimony.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. UGI Utilities, Inc. ("UGIU") is a combination gas distribution and electric utility. UGIU is a wholly-owned subsidiary of UGI Corporation ("UGI"). UGIU provides electric distribution service to approximately 62,500 customers in portions of Luzerne and Wyoming Counties. UGIU also provides natural gas distribution services to approximately 672,000 customers in 46 eastern and central Pennsylvania counties.

The deliveries (i.e., direct sales and Provider of Last Resort ("POLR")) on UGIU's electric system in 2021 were approximately 58% to residential, 31% to commercial, 10% to industrial, and 1% to other customers. Of these percentages, 24% were direct sales and 76% were POLR. The Company obtains energy for its POLR and direct sales services primarily from the wholesale market and also delivers electricity that customers purchase directly from other suppliers.

Q. How have you determined the cost of equity in the case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence, the cost of equity for an electric utility, such as the Company. In this regard, I have relied on four well recognized measures: the Discounted Cash Flow ("DCF") model, the Risk Premium analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings approach. By considering the results of a variety of approaches, I determined that 11.10% represents a reasonable cost of equity. To that equity cost rate, the Company is also entitled to a further 0.20% to recognize the strong performance of UGIU in the area of management effectiveness.

Q. In your opinion, what factors should the Commission consider when setting the Company's cost of capital in this proceeding?

A. The rate of return utilized by the Commission to set rates must be sufficient to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. What approach have you used in measuring the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed for my proxy group of ten (10) electric companies. The proxy group consists of electric companies that: (i) have publicly-traded common stock, (ii) are contained in The Value Line Investment Survey and are classified in the Electric Utility East group, (iii) are not currently the target of an announced merger or acquisition, and (iv) are not engaged in the construction of a nuclear generating plant. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the "Electric Group" throughout my testimony.

Q. How have you performed your cost of equity analysis with the market data for the Electric Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Electric Group. I have not measured separately the cost of equity for the individual companies within the Electric Group, because the determination of the cost of equity for an individual company has become increasingly problematic. If the models of the cost of equity were applied with individual company data, there is the possibility of anomalous results shown for selected companies, which would provide a misleading indication of the cost of equity. My approach of using average data for a portfolio of companies reduces the possibility that anomalous results might be shown by the models of the cost of equity. By employing group average data, rather than individual companies' analysis, I have helped to minimize the effect of extraneous influences on the market data for an individual company.

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[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity depending upon extraneous factors that may influence market sentiment. In an environment of high interest rates, the use of multiple methods is particularly compelling because the Risk Premium method and CAPM capture changes in interest rates much more expeditiously than does the DCF method. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches, as shown on page 2 of Schedule 1.

DCF	10.45%
Risk Premium	11.75%
CAPM	15.95%
Comparable Earnings	13.10%

From these measures, I recommend a cost of equity of 11.10%, prior to recognition for the Company's strong management performance. My determination of the cost of equity focuses on the DCF and Risk Premium approaches that provide a return of 11.10% (10.45% + 11.75% = 22.20% ÷ 2 = 11.10%). My 11.30% cost of equity recommendation includes 20 basis points or 0.20% recognition for the exemplary performance of the Company's management and falls within the range of 10.45% to 11.75% indicated above. Mr. Brown's testimony in UGI Electric Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness.

To obtain new capital to support an expanded construction program and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements. In recognition of its performance, the Company should be granted an opportunity to earn an 11.30% cost of equity.

ELECTRIC UTILITY RISK FACTORS

Q. Please identify some of the factors that make the electric utility industry generally different today than it was in the past.

A. Electric utilities generally are faced with a variety of challenges that affect their operations, while retaining the obligation to serve under cost of service pricing that continues to dominate their business risk profile. On January 1, 1999, customer choice was fully available on UGI Electric's system. From that point forward, UGI Electric's responsibility became primarily the provision of delivery service at regulated prices, while it also retained the responsibility for POLR service.

UGI Electric is part of the PJM Interconnection, LLC. Aside from its traditional responsibility to maintain reliability and comply with the mandates of PJM, a different set of risks apply to the electric delivery business in Pennsylvania.

The risk of distributed generation is a concern, and could have an increasing influence on the business of electric delivery utilities. With technological advances in micro-turbines, potential commercialization of fuel cells, development of wind and solar power, and the creation of micro-grids, utilities face the potential for bypass and the resulting declines in transmission and distribution revenues.

The cost to replace aging infrastructure also adds to the risk of electric delivery utilities, such as UGI Electric, because these expenditures increase costs without any concomitant increase in revenues, except through regulatory approved rate increases, such as the Distribution System Improvement Charge ("DSIC"). The Company continues to make substantial investments to increase the resiliency and reliability of its system to reduce the number and duration of storm-related outages experienced by customers. However, the DSIC mechanism contains a variety of limitations that will not eliminate the need for periodic rate cases to cover the significant new investment that is being made by UGI Electric.

Q. What are the primary risk factors facing the electric delivery utilities industry?

A. A pricing structure restricted by regulation diminishes management's ability to adjust its business strategy quickly to changing market conditions to respond to broadening competition and the potential for bypass arising from self-generation or distributed-generation. The financial structure of the electric business is uncertain due to the adequacy of capital recovery, counter-party risk, potential for financial penalties associated with operational problems, and growth in the utilization of the transmission and distribution network by non-affiliated generators and marketers. Regulatory risks include the overall framework of rate-setting, cost allocation, and rate design issues, and the level of return that will be allowed.

Q. Please indicate how the Company's risk profile is affected by its construction program.

A. Under its LTIIP, the Company is investing substantial capital to maintain and upgrade existing facilities in its service territory and to meet growth. Over the next five years, the Company's total capital expenditures (transmission and distribution), as shown in the table below, are expected to be $131.588 million:

Year	Capital Expenditures
2023	$ 31,064,491
2024	$ 24,566,590
2025	$ 24,336,000
2026	$ 25,309,442
2027	$ 26,311,478
Total	$ 131,588,001

These expenditures represent approximately 72% ($131.588 million ÷ $182.952 million) of the Company's net electric utility plant at December 31, 2021. Indeed, in the situation where capital expenditures are high, a reasonable return is a key to a financial profile that will allow for the attraction of capital on reasonable terms to fund these expenditures. A reasonable opportunity to experience a fair rate of return represents the key to a financial profile that will provide the Company with the ability to raise capital in all market conditions to meet its needs, and to satisfy investor requirements in an evolving industry.

Q. How should the Commission respond to the evolving business environment facing the Company?

A. In the situation where substantial additional capital is being invested, as shown by the projected construction expenditures indicated above, the regulatory process must establish a return on equity that provides a reasonable opportunity for the Company to actually achieve its cost of capital. Where ongoing capital investment is required to meet the high quality of service that customers demand, supportive regulation is essential.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for the determination of the cost of equity?

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company's risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared UGIU, which represents the combined electric and gas divisions, to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Electric Group. In this analysis, I have used UGIU on a consolidated basis as it is the consolidated capital structure that is used to compute the weighted average cost of capital for this case.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4. I have used this group as a broad-based measure of all types of regulated public utility endeavors.

Q. What companies comprise your Electric Group?

A. My Electric Group obtained from the Value Line publication consists of the following companies: AVANGRID, Inc., Consolidated Edison, Dominion Energy, Duke Energy, Eversource Energy, Exelon Corp., FirstEnergy Corp., NextEra Energy, PPL Corp., and Public Service Enterprise Group.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is an important determinant in analyzing a company's cost of equity because the cost of each type of capital is directly related to the associated risk of the firm. So, while a company's credit quality risk is directly shown by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus a premium to recognize the higher risk of an equity investment compared to debt.

Q. How do the bond ratings compare for the Company, the Electric Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer rating is A3 from Moody's, which resulted from a credit rating downgrade on December 13, 2022. In making the downgrade, Moody's stated that, among other factors, it was concerned with the Company's financial metrics that will be constrained by higher debt to fund elevated capital expenditures. As such, any inclination toward boosting the debt ratio in this case would be counter-productive and should be avoided so as to sustain its current credit quality rating. The LT issuer rating by Moody's focuses upon the credit quality of the issuer of the debt, rather than upon the debt obligation itself. The Company's credit quality is the same as the average A3 credit rating of the Electric Group. For the S&P Public Utilities, the average composite credit rating is also A3 by Moody's and BBB+ by S&P. Many of the financial indicators which I will subsequently discuss are considered during the rating process. It is important to note that credit quality ratings provide a comprehensive summary of a company's risk from a creditor's perspective.

Q. How do the financial data compare for the Company, UGIU, the Electric Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedule 2, 3 and 4. The data cover the five-year period 2017-2021. For UGIU, its financial profile is represented by the combined electric and gas divisions, which are the results presented to investors. This is because UGIU raises all of its capital requirements for both of its divisions. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, UGIU is very much smaller than the average size of the Electric Group and the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity. This is the case for UGIU as compared to the Electric Group and the S&P Public Utilities.

Market Ratios. Historical market-based financial ratios, such as price-earnings multiples and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies which exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

Since UGIU's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was fairly close for the Electric Group and the S&P Public Utilities. The five-year average dividend yield for the Electric Group was somewhat higher than the S&P Public Utilities. The average market-to-book ratios were somewhat lower for the Electric Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a higher common equity ratio has lower financial risk, while a firm with a lower common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital based on book value, were 55.3% for UGIU, 45.2% for the Electric Group, and 41.0% for the S&P Public Utilities. The capital structure of the Company for the FPFTY in this case is within the range of the Electric Group both historically and prospectively based upon the Value Line forecasts. It is noteworthy that the ratios for the Electric Group are calculated based upon the consolidated common equity for these holding companies. For rate setting purposes, the ratios for their utility subsidiaries are typically employed which contains higher common equity than the holding company ratios.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient

[2] For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.120 (1.4% ÷ 11.7%) for UGIU, 0.178 (1.6% ÷ 9.0%) for the Electric Group, and 0.051 (0.5% ÷ 9.9%) for the S&P Public Utilities. While less than the Electric Group, the Company's earnings variability was much higher when compared to the S&P Public Utilities. This signifies much higher risk for UGIU and the Electric Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[3] The five-year average operating ratios were 77.5% for UGIU, 78.6% for the Electric Group, and 79.8% for the S&P Public Utilities. The operating ratio for UGIU was similar to the Electric Group, thus indicating similar risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding Allowance for Funds Used During Construction ("AFUDC")) was 4.89 times for UGIU, 3.00 times for the Electric Group, and 2.97 times for the S&P Public Utilities. The higher interest coverage for UGIU suggests lower credit risk, although its bond rating is similar to the other groups.

Quality of Earnings. Measures of earnings quality are usually revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds. Quality of earnings has not been a significant concern for UGIU and the Electric Group.

[3] The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to construction expenditures was 73.7% for UGIU, 68.3% for the Electric Group, and 66.0% for the S&P Public Utilities. This indicates a fairly comparable risk for the Company and the reference groups.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[5] A comparison of market risk is shown by the Value Line betas of .88 as the average for the Electric Group provided on page 2 of Schedule 3 and .90 as the average for the S&P Public Utilities provided on page 3 of Schedule 4. The systematic risk was similar for the Electric Group and the S&P Public Utilities.

Q. Please summarize your risk evaluation of UGIU and the Electric Group.

A. The investment risk of UGIU parallels that of the Electric Group in certain respects. In certain regards, UGIU has higher risk traits due to its relatively small size and the "negative" outlook on its credit quality. UGIU has lower risk as shown by its higher common equity and higher interest coverages. Operating ratios, quality earnings and

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[4] Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The ''Beta coefficient'' is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

[5] The procedure used to calculate the beta coefficient published by Value Line is described on page 3 of Schedule 14. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

IGF to construction indicate comparable risk to the Electric Group. On balance, the cost of equity for the Electric Group would fairly represent the Company's cost of equity for this case, albeit on the conservative side because of the small size of UGI Electric.

RECOMMENDED CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGIU in this case.

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGIU, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed and the capital cost rates are directly identifiable. The circumstances of UGIU indicate that its capital structure ratios should be used for rate of return purposes for each of its utility divisions, because the Company attracts all of its capital on a combined basis and investors make their capital commitments on that basis.

Q. Does Schedule 5 provide the capitalization and capital structure ratios you have considered?

A. Yes. Schedule 5 presents UGIU capitalization and related capital structure at September 30, 2022, the end of the historic test year ("HTY"). Also, shown on Schedule 5 is the UGIU capital structure estimated at September 30, 2023, the end of the future test year ("FTY"), and at September 30, 2024, the end of FPFTY. The changes in the Company's capital structure consist of: (i) sinking fund payments of $6.250 million in the FTY and FPFTY on the Senior Notes due in 2027, (ii) the issuance of $225 million of long-term debt in the FPFTY, and (iii) the Company's projection of retained earnings at the end of the FTY and FPFTY. The Company's planned issuance of long-term debt is part of the financial plan reflected in its budgeting process.

Q. Have you made adjustments to the Company's capitalization for rate-setting purposes?

A. Yes. I have removed the capitalized lease obligations from the Company's debt and removed the accumulated other comprehensive income ("OCI") from the Company's common equity account.

Q. Why have you removed capitalized lease obligations from the Company's capital structure?

A. I have made this elimination because for rate-setting purposes, the Company includes its total lease obligations as operating leases. That is to say, the total amount of lease payments, including both the principal and interest, is reflected in the Company's operating expenses. To avoid double-counting, capitalized leases must be removed from the capital structure for rate-setting purposes.

Q. Please explain the justification for removing the accumulated OCI.

A. The accumulated OCI must be eliminated from the capital structure for rate-setting purposes. OCI arises from a variety of sources, including: minimum pension liability ("MPL"), foreign currency hedges, unrealized gains and losses on securities available for sale, interest rate swaps, and other cash flow hedges. The accumulated OCI for the Company has its roots in the MPL and interest rate hedges associated with the variable-rate term-loan. An MPL entry must be recorded on the balance sheet when the present value of the pension benefit earned by employees exceeds the market value of trust fund assets. It should be noted that the Company records the change related to prior service cost and actuarial valuations as a regulatory asset for the portion of pension attributable to its retirees and employees that are part of its regulated utility operations. The amount in the accumulated OCI is just related to the portion attributable to employees of UGI Corporation and non-utility subsidiaries. That is to say, the accumulated OCI associated with MPL is not related to utility operations. The interest rate hedges, as they affect OCI, must also be removed because they have been reflected in the embedded cost of debt.

Q. Have you included short-term debt in the capital structure for UGIU?

A. No. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the historic test year, the FTY, and the FPFTY and compared those amounts to the Company's construction work in progress ("CWIP"). I have done this because the Company follows the FERC formula to calculate its AFUDC rate. That formula assigns short-term debt first to CWIP, with any excess balance of CWIP receiving the Company's overall rate of return. In order to avoid double-counting the amount of short-term debt that finances CWIP, those amounts must be removed from the average short-term debt amounts for rate case purposes. For the FPFTY, the CWIP balances approximately offsets the average amount of short-term debt. Therefore, the de minimis remaining amount of short-term debt is removed from the capital structure for the FPFTY.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratemaking is prospective, the rate of return should reflect known conditions that will exist during the period of time the proposed rates are to be effective. I will adopt the Company's capital structure ratios at the end of the FPFTY of 45.41% long-term debt and 54.59% common equity. These ratios are within the ranges indicated for the Electric Group. I should note that due to the small size of UGIU and UGI Electric, less debt and more equity would be appropriate and an equity ratio in the upper end of the range would be warranted. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

EMBEDDED COST OF DEBT

Q. What cost rate have you assigned to the long-term debt portion of the capital structure?

A. Consistency requires that the embedded senior capital cost rates of UGIU must be used for developing a fair rate of return. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2022. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2023. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. For the proposed issue of $225.000 million of new long-term debt to be issued in the FPFTY, the coupon rate is very conservatively estimated to be 4.551% and the effective cost rate is 4.60%. Indeed, due to the recent volatility of interest rates, the Company intends to update its cost of debt at the time of its rebuttal testimony. The development of the individual effective cost rates for each series of long-term debt, using the cost rate to maturity technique, is shown on page 4 of Schedule 6. The cost rate, or yield to maturity, is the rate of discount that equates the present value of all future interest and principal payments with the net proceeds of the bond.

I will adopt the 4.35% forecast embedded long-term debt cost rate at September 30, 2024, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 45.41% long-term debt ratio.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe how you determined the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGI Electric, the Electric Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings also must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Electric Group and arrived at a cost of equity of 11.30% for UGI Electric, which includes an increment for exemplary management performance.

DISCOUNTED CASH FLOW

Q. Please describe the DCF model.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF-determined return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model, which assumes that future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: P = D/(k-g), where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: k= D/P + g. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[6] My DCF results are provided on Schedule 1, page 2, for the Electric Group. The DCF return is 10.45% with the leverage adjustment and 9.48% without the leverage adjustment for the Electric Group. The leverage adjustment is discussed more fully below.

Among the limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility. Other limitations of the DCF include the constant P-E multiple assertion that does not conform with actual stock market performance. And, indeed, the FERC has moved to using multiple methods for measuring the cost of equity due to the limitations of the DCF. Further, the DCF method is slow to reflect changes in interest rates. Hence, the DCF should always be used along with other methods that are more responsive to changes in interest rates.

Q. What is the dividend yield component of a DCF analysis?

A. The dividend yield reveals the portion of investors' cash flow that is generated by the return provided by the dividends an investor receives. It is measured by the dividends

[6] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950s, J.B. Williams exposited the DCF model in its present form nearly two decades earlier.

per share relative to the price per share. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended September 2022, the monthly dividend yields are shown on Schedule 7. The month-end prices were adjusted to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended October 2022, the average dividend yield was 3.37% for the Electric Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month and three-month periods were 3.37% and 3.53%, respectively. For applying the DCF model, I have used the six-month average dividend yield of 3.37% for the Electric Group. The use of this dividend yield will reflect current capital costs while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investors' anticipated cash flows. I have adjusted the six-month average dividend yield in three different but generally accepted manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7.[7] This

[7] These adjustments are the 1/2 growth approach, the discrete approach, and the quarterly approach. Under the 1/2 approach, the procedure to adjust the average dividend yield for the expectation of a dividend increase during the initial investment period will be at a rate of one-half the growth component, which assumes that half of the dividend payments will be at the expected higher rate during the initial investment period. Under the discrete approach, the "*g*" in the DCF model reflects the discrete growth in the quarterly dividend, which is required for the periodic form of the DCF to properly recognize that dividends are expected to grow on a discrete basis. The quarterly approach takes into account that investors have the opportunity to reinvest quarterly dividend receipts. Recognizing the compounding of the periodic quarterly dividend payments *(D_0)* results in this third DCF formulation. This DCF equation provides no further recognition of growth in the quarterly dividend. A compounding of the quarterly dividend yield recognizes the necessity for an adjusted dividend yield.

adjustment adds eleven basis points to the six-month average historical yield, thus producing the 3.48% adjusted dividend yield for the Electric Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future growth in earnings per share is the DCF model's primary focus because, under the model's assumption that the P-E multiple remains constant, the price per share of stock will grow at the same rate as earnings per share. A growth rate analysis considers a variety of variables to reach a consensus of prospective growth, including historical data and widely available analysts' forecasts of earnings, dividends, book value, and cash flow (all stated on a per-share basis). A fundamental growth rate analysis is frequently based upon internal growth, or b x r, where "r" is the expected rate of return on common equity and "b" is the retention rate (a fraction representing the proportion of earnings not paid out as dividends). To be complete, the internal growth rate should be modified to account for sales of new common stock (external growth), which is represented by the formula s x v, where "s" is the number of new common shares that the firm expects to issue and "v" is the value that accrues to existing shareholders from selling stock at a price above book value. Fundamental growth, which combines internal and external growth, encompasses the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage during which a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage during which fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" stage, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilize at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps up and ramps down in cycles over time. For these reasons, there is no need to analyze growth rates individually for each cycle, but rather to rely upon analysts' growth forecasts that are used by investors when pricing common stocks.

Q. What factor should be considered in the determination of an appropriate growth rate?

A. The growth rate used in a DCF calculation should measure investor expectations. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. Investors are not influenced solely by a single set of company-specific variables weighted in a formulaic manner. Therefore, all relevant growth rate indicators should be evaluated using a variety of techniques when formulating a judgment of investor-expected growth.

Q. What data for the Electric Group have you considered in your growth rate analysis?

A. I considered the growth in the financial variables shown on Schedules 8 and 9, which reflect historical (Schedule 8) and projected (Schedule 9) rates of growth in earnings per share, dividends per share, book value per share, and cash flow per share for the Electric Group. While analysts will review all measures of growth, as I have done, earnings per share growth directly influences the expectations of investors for the future performance of utility stocks. Forecasts of earnings growth are required because the DCF model is forward-looking, and, with the constant P-E multiple and constant payout ratio that the DCF model assumes, all other measures of growth will mirror earnings growth. The historical growth rates, which were also reviewed to gain a perspective on the industry, were obtained from the Value Line publication that provides this data. While historical data cannot be ignored, they are much less significant when applying the DCF model than projections of future growth. Investors cannot purchase the past earnings of a utility. To the contrary, they are only entitled to future earnings, which are the focus of growth projections. Furthermore, if significant weight is assigned to historical performance, the historical data are double-counted because they are already factored into analysts' forecasts of earnings growth.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes, it is. Although the constant form of the DCF model assumes an infinite stream of cash flows, investors do not expect to hold an investment indefinitely. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investors' expected return. The growth in the price per share will equal the growth in earnings per share if, as the DCF model assumes, there is no change in the price-earnings ("P-E") multiple. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences investors' expectations of their actual total return. Moreover, academic research also focuses on five-year growth rates specifically because market outcomes occurring over that investment horizon are what influence stock prices. Indeed, if investors required forecasts beyond five years in order to properly value common stocks, then it would be reasonable to expect that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of the marketplace. The absence of such a publication suggests that there is no market for this information because investors do not require forecasts for an infinite series of future data points in order to make informed decisions to purchase and sell stocks.

Q. What are the analysts' forecasts of future growth that you considered?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' five-year forecasts compiled by IBES/First Call, Zacks, and Value Line. These are all reliable authorities of projected growth that investors use to make buy, sell, and hold decisions. The IBES/First Call and Zacks estimates are obtained from the Internet and are widely available to investors. The growth rates reported by IBES/First Call and Zacks are consensus forecasts taken from a survey of analysts that make growth projections for these companies. Notably, First Call's earnings forecasts are frequently quoted in the financial press. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free of charge at most public and collegiate libraries. The IBES/First Call and Zacks forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share for the Electric Group are also included on Schedule 9.

Q. What are the projected growth rates published by the sources you discussed?

A. Schedule 9 shows the prospective five-year earnings per share growth rates projected for the Electric Group by IBES/First Call (6.25%), Zacks (5.89%), and Value Line (4.83%).

Q. Are certain growth rate forecasts entitled to greater weight in developing a growth rate for use in the DCF model?

A. Yes. While a variety of factors should be examined to reach a reasonable conclusion on the DCF growth rate, growth in earnings per share should receive the greatest emphasis. Growth in earnings per share is the primary determinant of investors' expectations of the total returns they will obtain from stocks because the capital gains yield (i.e., price appreciation) will track earnings growth if the P-E multiple remains constant, as the DCF model assumes. Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In fact, Professor Gordon, the foremost proponent of the use of the DCF model in setting utility rates, concluded that the best measure of growth for use in the DCF model is a forecast of earnings per-share growth.[8] Consistent with Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, and Value Line, provide the best indication of investor expectations.

Q. What growth rate do you use in your DCF model?

A. The forecasts shown on Schedule 9 for the Electric Group exhibit a range of average earnings per share growth rates from 4.83% to 6.25%. DCF growth rates should not be established by mathematical formulation, and I have not done so. In my opinion, a growth rate of 6.00% is a reasonable estimate of investor-expected growth for the Electric Group. This value is within the array of analysts' forecasts of five-year earnings per share growth rates. The reasonableness of this growth rate is also supported by the expected continuation of electric utility infrastructure spending.

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[8] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

Q. Are the dividend yield and growth components of the DCF adequate to accurately depict the rate of return on common equity when it is used to calculate a utility's weighted average overall cost of capital?

A. The components of the DCF model are adequate for that purpose only if the capital structure ratios are measured by the market value of debt and equity. In the case of the Electric Group, average capital structure ratios are 40.58% long-term debt, 0.49% preferred stock, and 58.93% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then a leverage adjustment is required.

Q. What is a leverage adjustment?

A. If a firm's capitalization, as measured by its stock price, diverges from its capitalization, measured at book value, the potential exists for a financial risk difference. Such a risk difference arises because a market-valued capitalization contains more equity and less debt than a book-value capitalization and, therefore, has less risk than the book-value capitalization. A leverage adjustment properly accounts for the risk differential between market-value and book-value capital structures.

Q. Why is a leverage adjustment necessary?

A. In order to make the DCF results relevant to the capitalization measured at book value (as is done for rate setting purposes), the market-derived cost rate must be adjusted to account for this difference in financial risk. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different from the capital structure indicated by the market price (P). From the market perspective, the financial risk of the Electric Group is accurately measured by the capital structure ratios calculated from the market-valued capitalization of a firm. If the ratemaking process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratemaking process uses ratios calculated from a firm's book value capitalization, further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the firm's equity. This adjustment is developed through precise mathematical calculations, using well-recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M,"[9] provide a return of 8.10% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book value are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of

[9] Franco Modigliani and Merton H. Miller, "The Cost of Capital, Corporation Finance, and the Theory of Investments," American Economic Review, June 1958, at 261-97. Franco Modigliani and Merton H. Miller, "Taxes and the Cost of Capital: A Correction," American Economic Review, June 1963, at 433-43.

equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on the book value of equity that differs from their cost of equity determined from stock market prices. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they actually exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true: when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. What I label a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g) when the DCF return applies to a capital structure used for ratemaking that is computed with book-value weighting rather than market-value weighting. Although I specify a separate factor, which I call the leverage adjustment, there is no need to do so other than to identify this factor. If I were to express my return solely in the context of the book value weighting that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then a separate element in the DCF cost of equity determination would not be needed to reflect the differential in financial leverage between a market-value and book-value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 8.10%, which is the return for the Electric Group appropriate for a capital structure with no debt (i.e., a 100% equity ratio) plus 2.31% to compensate investors for the risk of a 53.41% debt ratio and 0.04% for a 0.73% preferred stock ratio. These are the book-value ratios that differ markedly from the market-value based ratios I discussed previously. Under this approach, the parts add up to 10.45% (8.10% + 2.31% + 0.04%), and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I added the 3.48% dividend yield, the 6.00% growth rate, and 0.97% for the leverage adjustment in order to arrive at the same 10.46% (3.48% + 6.00% + 0.97%) return. I know of no means to mathematically solve for the 0.97% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.97% adjustment is merely a convenient way to compare the 10.45% return computed using the Modigliani & Miller formulas to the 9.48% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF shown on Schedule 1, page 2) based on a market-value capital structure. A 9.48% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ($D_{1/}P_0$) adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate (g) previously developed. The DCF also includes the leverage modification (Lev.) required when the book value equity ratio is used in determining the weighted average cost of capital in the ratemaking process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is 10.45%, computed as follows:

	D_1/P_0	+	g	+	$lev.$	=	k
Electric Group	3.48%	+	6.00%	+	0.97%	=	10.45%

The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant-growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the P-E multiple. An assumption that there will be no change in the P-E multiple is not supported by the realities of the equity market because P-E multiples do not remain constant. This is one of the constraints of this model that makes it important to consider the results of other models when determining a company's cost of equity.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the Risk Premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on Schedule 1, page 2. That result is 11.75%.

Q. What long-term public utility debt cost rate did you use in your Risk Premium analysis?

A. In my opinion, and as I will explain in more detail further in my testimony, a 5.50% yield represents a reasonable estimate of the prospective yield on long-term, public utility bonds.

Q. What historical data are shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on Schedule 11, page 1. For the twelve months ended October 2022, the average monthly yield on Moody's index of A-rated public utility bonds was 4.31%. For the six- and three-month periods ended October 2022, the yields were 5.05% and 5.31%, respectively. During the twelve months ended October 2022, the range of the yields on A-rated public utility bonds was 3.02% to 5.88%. Page 2 of Schedule 11 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.52% on a twelve-month average basis, 1.69% on a six-month average basis, and 1.73% on a three-month average basis. With these data, 1.50% represents a reasonable, albeit conservative, spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on November 1, 2022 and a yield spread of 1.50%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2022	Fourth	5.3%	6.3%	4.0%	1.50%	5.30%
2023	First	5.5%	6.5%	4.1%	1.50%	5.40%
2023	Second	5.4%	6.5%	4.1%	1.50%	5.50%
2023	Third	5.4%	6.4%	4.0%	1.50%	5.40%
2023	Fourth	5.3%	6.3%	3.9%	1.50%	5.30%
2024	First	5.1%	3.2%	3.9%	1.50%	5.30%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its June 1, 2022 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2023-2027	4.9%	5.9%	3.8%
2028-2032	5.0%	5.9%	3.9%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. A 5.50% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. All the data I used to formulate my conclusion as to a prospective yield on A-rated public utility debt are available to investors, who regularly rely upon such data to make investment decisions. Recent FOMC pronouncements have moved the forecasts of interest rates to higher levels.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from 2022 SBBI Yearbook, Stocks, Bonds, Bills and Inflation. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline, and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on Schedule 12, page 1.

Common Equity Risk Premiums	
Low Interest Rates	6.81%
Average Across All Interest Rates	5.93%
High Interest Rates	5.05%

Based on my analysis of the historical data, the equity risk premium was 6.81% when the marginal cost of long-term government bonds was low (i.e., 2.80%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.03% on average during periods of high interest rates), the spread narrowed to 5.05%. Over the entire spectrum of interest rates, the equity risk premium was 5.93% when the average government bond yield was 4.92%. From these data, I have utilized a 6.25% equity risk premium. The equity risk premium of 6.25% is between the premiums associated with low interest rates (i.e., 6.81%) and average for the entire historical period interest rates (i.e., 5.93%).

Q. What common equity cost rate did you determine based on your Risk Premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i") and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

Electric Group	5.50%	+	6.25%	=	11.75%

CAPITAL ASSET PRICING MODEL

Q. How is the CAPM used to measure the cost of equity?

A. The CAPM uses the yield on a risk-free interest-bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 15.95% for the Electric Group with the leverage adjustment. Without the leverage adjustment, the CAPM result is 13.93% (15.95% - (0.20 x 10.12%)) through use of the Value Line beta excluding the leverage adjustment (i.e., 1.08 - 0.88 = 0.20). To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.88 for the Electric Group.

Q. Did you use the Value Line betas in the CAPM determined cost of equity?

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The Value Line betas are measured over a five-year period. The betas must be reflective of the financial risk associated with the ratemaking capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. Since we used book values in this case, the Value Line betas must be adjusted for the higher financial risk associated with the book value capital structure. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and re-leveraged for the book value common equity ratios using the Hamada formula,[10] as follows:

$$\beta l = \beta u\ [1 + (1 - t)\ D/E + P/E]$$

ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.60 for the Electric Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada," who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 1.08 for the book value capital structure of the Electric Group.

[10] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks;" The Journal of Finance, Vol. 27, No. 2; Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, Dec. 27-29, 1971. (May 1972), pp. 435-52.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2022, the average yield on 30-year Treasury bonds was 2.79%. For the six- and three-months ended October 2022, the yields on 30-year Treasury bonds were 3.36% and 3.58%, respectively. During the twelve months ended October 2022, the range of the yields on 30-year Treasury bonds was 1.85% to 4.04%. The low yields that existed during 2020 can be traced to extraordinary events associated with the Pandemic that jolted the capital markets. I described these events in my pre-filed direct testimony previously. Much higher rates are currently in place. A forward-looking assessment of the capital markets is especially relevant now because the Company's rates will be based on financial conditions in 2024 and beyond. Higher inflation expectations are a contributing factor that points to higher interest rates. Indeed, higher inflation today is revealed by an 8.7% increase in 2023 Social Security payments announced on October 13, 2022, which is the largest one-year increase in four decades. This is symptomatic of high rates of inflation that are pushing upward the cost of capital.

This is revealed by the end of accommodative policy by the FOMC. Tighter monetary policy has promoted higher interest rates that have already occurred and will continue in the future. The Fed Funds rate is expected to continue to increase from very low levels that existed during the Pandemic. After the FOMC ended its bond-buying program (i.e., quantitative easing) in March 2022, it now plans to run off its $9 trillion asset portfolio, which will further boost interest rates, particularly those with 10 and 30-year maturities.

Higher interest rates clearly point to higher capital costs prospectively, as indicated by recent bond yield changes. The yield on 10-year Treasury bonds moved above the 3% level on May 2, 2022, the first time since late 2018. By October 2022, the yield on 30-year Treasury bonds moved to 4.04%, or an increase of 2.37% (or 142%) since December 2020.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on November 1, 2022, indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.9% to 4.1% during the next six quarters. The forecasts show interest rates remaining at high levels through the second quarter of 2023, and then some moderation thereafter. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.8% from 2023 through 2027 and 3.9% from 2028 to 2032. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 4.00% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts, and is conservative.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on Schedule 13, page 2, the market premium is derived from historical data and the forecast returns. For the historically based market premium, I have used the arithmetic mean obtained from the data presented on Schedule 12, page 1. On that schedule, the market return was 12.21% on large stocks during periods between the low interest rate environment and the entire long-term average. During those periods, the yield on long-term government bonds was 3.86% (2.80% + 4.92% = 7.72% ÷ 2). Likewise, I carried over to Schedule 13, page 2, the average large common stock returns of 12.21% (12.09% + 12.33% = 24.42% ÷ 2) and the average yield on long-term government bonds of 3.86%. The resulting market premium is 8.35% (12.21% - 3.86%) based on historical data, as shown on Schedule 13, page 2. As also shown on Schedule 13, page 2, I calculated the forecast returns, which show a 15.89% total market return. With this forecast, I calculated a market premium of 11.89% (15.89% - 4.00%) using forecast data. The resulting market premium applicable to the CAPM derived from these sources equals 10.12% (11.89% + 8.35% = 20.24% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Eugene F. Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms. Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns;" <u>The Journal of Finance</u>, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could significantly understate the cost of equity according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) had returns in excess of those shown by the simple CAPM. To recognize this fact, I used the mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13, for the CAPM calculation. The adjustment here is related to the size of the Electric Group.

Q. What does your CAPM analysis show?

A. Using the 4.00% risk-free rate of return, the leverage adjusted beta of 1.08 for the Electric Group, the 10.12% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	+ (	*β*	x (*Rm-Rf*))	+	*size*	=	*k*
Electric Group	4.00%	+ (	1.08	x (10.12%))	+	1.02%	=	15.95%

The CAPM results shown here should receive more weight in an environment of rising interest rates, because the DCF will provide an understated result. Indeed, the

Commission has used the results of the CAPM when the DCF is producing atypical results.

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar risk characteristics would need to realize in order to compete for capital. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into investor expectations for public utility returns. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial

> soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works v. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. Did you compare the results of your DCF and CAPM analyses to the results indicated by a Comparable Earnings approach?

A. Yes. I selected companies from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Electric Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Electric Group. The items considered were Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on Schedule 14, page 3. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on Schedule 14, page 1.

I relied upon Value Line data because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on Schedule 14, page 2, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data did you consider in your Comparable Earnings analysis?

A. I used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 12.8% using only the returns that were less than 20%, as shown on Schedule 14, page 2. The average forecasted rate of return as published by Value Line is 13.4% also using values less than 20%, as provided on Schedule 14, page 2. Using the average of these data, my Comparable Earnings result is 13.10%, as shown on Schedule 1, page 2.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of a variety of methods and models described previously, it is my opinion that a reasonable rate of return on common equity is 11.30% for UGI Electric, which includes twenty basis points or 0.20% for recognition of the Company's strong management performance. My cost of equity recommendation is within the range of results and should be considered in the context of the Company's risk characteristics relative to the Electric Group companies. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method. In summary, the Company should be provided an opportunity to realize an 11.30% rate of return on common equity so that it can compete in the capital markets, attain reasonable credit quality, sustain its cash flow in the context of its high levels of capital expenditures, and receive recognition of the significant accomplishments that management has achieved.

Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

UGI ELECTRIC

EXHIBIT PRM-1

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented rebuttal testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 300 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509).

I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

UGI ELECTRIC STATEMENT NO. 10

SHERRY A. EPLER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2022-3037368

UGI Utilities, Inc. – Electric Division

Statement No. 10

Direct Testimony of
Sherry A. Epler

Topics Addressed:	**Sales and Revenues** **Tariff Changes**

Dated: January 27, 2023

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Sherry A. Epler. My business address is 1 UGI Drive, Denver, PA 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Manager, Tariff & Supplier Administration. UGI is a wholly-owned subsidiary of UGI Corporation ("UGI Corp."). UGI has two operating divisions, the Electric Division ("UGI Electric" or the "Company") and the Gas Division ("UGI Gas"), each of which is a public utility regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Manager, Tariff & Supplier Administration with respect to UGI Electric?

A. My current responsibilities related to UGI Electric include: (1) all aspects of tariff and rate administration, including interactions with electric retail suppliers under the Company's electric supplier tariff; and (2) revenue analysis.

Q. Please provide your educational background and professional experience.

A. Please see my resume, UGI Electric Exhibit SAE-1, which is attached to my testimony.

Q. Have you testified previously before the Pennsylvania Public Utility Commission?

A. Yes. UGI Electric Exhibit SAE-1 contains a list of those proceedings.

Q. Please describe the purpose of your testimony.

A. I will address: (1) the development of sales and revenue for the historic test year ended September 30, 2022 ("HTY"), future test year ending September 30, 2023 ("FTY"), and fully projected future test year ending September 30, 2024 ("FPFTY"); and (2) and certain proposed tariff modifications.

Q. Are any other witnesses providing testimony on the areas you identified above?

A. Yes. Company witness John D. Taylor, Managing Partner of Atrium Economics, LLC (UGI Electric Statement No. 6) is sponsoring allocation of the revenue increase and rate design, in addition to his testimony supporting class cost of service, using the projected sales and revenue figures discussed in my testimony. Additionally, Company witness Eric W. Sorber (UGI Electric Statement No. 4) is sponsoring certain proposed tariff modifications.

Q. Are you sponsoring any exhibits or filing requirements in this proceeding?

A. Yes, I am sponsoring the following Exhibits: UGI Electric Exhibit SAE-1 (Resume), UGI Electric Exhibit SAE-2 (15 Year Normal Heating and Cooling Degree Days 2005-2019), UGI Electric Exhibit SAE-3 (UGI Electric Customer Counts), UGI Electric Exhibit SAE-4 (Fully Projected Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-5 (Future Test Year Sales and Revenue Adjustments), UGI Electric Exhibit SAE-6 (Historic Test Year Sales and Revenue Adjustments), UGI Electric Exhibit E (Proof of Revenue), and certain portions of UGI Electric Exhibit F (Proposed Tariff). I am also sponsoring certain responses to the Commission's standard filing requirements, as indicated on the matter list accompanying this filing, that were prepared by me or under my direction.

II. TEST YEARS' SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

Q. Please explain how the Company's FPFTY sales and revenues were developed.

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2024 fiscal year planned sales and revenue budget. Annualized sales were determined by developing sales and revenue adjustments reflective of annual expected use per customer and projected customer counts as of the end of the FPFTY, or September 30, 2024. UGI Electric Exhibit SAE-2 provides the development of the Company's normal degree day values, which are based on the 15-year period 2005-2019. This data was used in normalizing use per customer for degree days. The Company's 15-year normal is updated every 5 years, with the most recent being the 15-year period of 2005-2019.

Q. Please explain the process for developing the Company's fiscal year ("FY") 2023 planned sales and revenue budget.

A. The planned sales and revenue budget for FY2023 or the FTY was developed by the Financial Planning and Analysis ("FP&A") group with input from various UGI Electric personnel. Historical data is used in developing a forecast of sales and revenue. Because of the static nature of the Company's customer base, the Company developed the budgeted number of customers for both the FTY and FPFTY by using the actual average customer count for FY2022. The Marketing group provided data for major customer additions for incorporation in the budgeted customer numbers.

UGI Electric Exhibit SAE-3 provides the actual historical customer count and illustrates the relatively static nature of the service territory. The budgeted sales-kilowatt hours ("kWh") were developed using a two-year average of the sales-kWh for each month for a two-year period ended April 2022. The revenue budget is then calculated by applying tariff rates for each customer class to budgeted sales. The sales and revenue budget is then reviewed and approved by senior management. The complete budget process is described in the direct testimony of Company witness Tracy A. Hazenstab (UGI Electric Statement No. 2).

Q. Please describe the adjustments made to FPFTY sales and revenues for the 12 months ending September 30, 2024.

A. A summary of all adjustments made to the 2024 planned budget in order to develop FPFTY sales is shown on UGI Electric Exhibit SAE-4(a). In total, these adjustments reflect an increase to sales of 35,942,000 kWh, or 3.52%, with a net upward adjustment to margin of $2,252,000, and a net increase to revenues of $7,388,000.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Electric Exhibit SAE-4(b).

A. The "Adjustment for Customer Changes" annualizes customer counts for certain rate classes to anticipated end-of-test-year levels. The Company projects customer growth forward from September 2022 actual levels based on a two-year average growth pattern from year end September 2020 to year end September 2021 and from year end September 2021 to year end September 2022, as shown in the presented customer rate categories.

Q. How is this adjustment quantified?

A. UGI Electric Exhibit SAE-4(b) provides the calculation of the associated sales and revenue adjustments related to customer count changes and reflects customer count increases for default service customers taking service under Rate R-General, Rate R-Heating, and Rate GS-1-Commercial General and a decrease for Rate GS-4-Commercial General. Adjustments were made to these four rate class categories as they comprise the majority of customer counts and the largest total margin dollars for the Company. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment increases sales by 5,393,000 kWh and increases projected revenues by $912,000. The impact to margin is an increase of $167,000.

Q. Please explain the adjustment for "Normalized Use/Customer."

A. As noted earlier, the sales-kWh values for the budget were developed using a two-year average of the sales-kWh for each month for a two-year period ending April 2022. As the associated average degree days for these periods differ from the Company's 15-year period used to define normal degree days for ratemaking purposes, or normal weather, an adjustment is necessary to normalize usage to the Company's stated 15-year normal weather. This adjustment utilizes the variance between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days to calculate the normalizing adjustments. *See* UGI Electric Exhibit SAE-2 for related degree day data. UGI Electric Exhibit SAE-4(c) shows the calculation of the adjustment of the use per default service customer taking service under Rate R-General, Rate R-Heating, Rate GS-1-Commercial General, and Rate GS-4-Commercial General, respectively. As shown in this exhibit, this adjustment is calculated by applying the heating and cooling sensitivity per degree day to the difference between the calculated average degree days for the periods utilized for budget development and the Company's 15-year normal degree days. In total, as reflected on UGI Electric Exhibit SAE-4(a), this adjustment increases sales by 30,549,000 kWh and increases projected revenues by $5,513,000. The impact to margin is an increase of $1,179,000.

Q Please explain the adjustment on UGI Electric Exhibit SAE-4(d) "Adjustment for STAS."

A. The "Adjustment for STAS" is the calculated State Tax Adjustment Surcharge ("STAS") on all Revenue adjustments presented in UGI Electric Exhibits SAE-4(b), (c), and (e). This STAS adjustment increases projected revenues by $1,000 with no impact to margin.

Q. Please explain the "Adjustment for DSIC" on UGI Electric Exhibit SAE-4(e).

A. The "Adjustment for DSIC" annualizes the Distribution System Improvement Charge ("DSIC") rate to reflect end of FPFTY conditions. This DSIC adjustment increases projected revenues by $963,000 and increases projected margins by $906,000.

B. Development of Sales and Revenue for the FTY and HTY

Q. How were normalized and annualized sales and revenue determined for the FTY ending September 30, 2023?

A. Budgeted sales and revenues served as the starting point for the development of the normalized and annualized FTY sales and revenues summarized on UGI Electric Exhibit SAE-5(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the FTY with the exception of the “Adjustment for DSIC.” These detailed adjustments are contained in UGI Electric Exhibits SAE-5(b)-(d).

Q. How were normalized and annualized sales and revenue determined for the HTY ended September 30, 2022?

A. Historic sales and revenues served as the starting point for the development of the normalized and annualized HTY sales and revenues shown in summary on UGI Electric Exhibit SAE-6(a). All of the adjustments that were made in the development of the FPFTY were also made in the development of the HTY, except for the “Adjustment for DSIC.” Additional adjustments were made, which include: (1) “Adjustment for GSR-1” to annualize historic GSR-1 rates to the September 1, 2022 rate of $0.12902/kWh; (2) “Adjustment for USP” to annualize historic USP rates to the September 1, 2022 rate of $0.0115/kWh; and (3) “Adjustment for EEC” to annualize historic Energy Efficiency and Conservation (“EEC”) rates to the September 1, 2022 rate of $0.00059/kWh for Class 1, $0.00132/kWh for Class 2, and $0.00203/kWh for Class 3 customers. These detailed adjustments are contained in UGI Electric Exhibits SAE-6(b)-(g).

III. <u>TARIFF MODIFICATIONS</u>

Q. What tariff changes are being proposed in this case?

A. The Company is revising references to the Supplement Number, Notice Language, Issue and Effective Dates, and page numbers as necessary; in accordance with 52 Pa. Code Chapter 53 standards. Apart from the proposed rate schedule changes (in accordance with this rate case filing), a complete list of tariff modifications are found in the List of Changes

Made by the Supplement section in UGI Gas Exhibit F – Proposed Supplement No. 51 to UGI Electric Tariff No. 6. More significant proposed changes to the tariff include:

- Rider A – The State Tax Adjustment Surcharge was rolled into rates and reset to 0.00%.
- Rider C – Universal Service Program was revised so the Customer Assistance Program ("CAP") credit bad debt offset will be associated with the participants in excess of the number of CAP enrollees as of September 30, 2023, in place of the existing September 30, 2021 date. This proposal is consistent with the establishment of the CAP enrollee figure in the last UGI Electric rate case at Docket No. R-2021-3023618.
- Rider G – DSIC was reset to 0.00% in accordance with 66 Pa. C.S. § 1358(b).

Q. Is the Company adding a definition for Contribution in Aid of Construction to its tariff?

A. Yes. The Company is adding a definition for Contribution in Aid of Construction to the "Definitions – General" part of its Electric tariff. There are various places in the current tariff where customers are required to pay UGI Electric for extending service, relocating facilities, or upgrading the system to accommodate customer needs (e.g., Rules 5, 17, 19 and various rate schedules). The definition clarifies the term's application in these situations as "a non-refundable cash contribution from an Applicant/Customer for those costs associated with a line extension, temporary service, or relocation of Company facilities, including all related activities." The term also replaces "aid in construction," which appears in different subparts of Rules 5, 17, and 19.

Q. What changes is UGI Electric proposing to Rule 16-b "Administration of Rates" in the tariff?

A. The Company is proposing a few revisions to Rule 16-b. First, UGI Electric is revising the title of Rule 16-b from "Billing Changes" to "Billing Corrections" to more adequately reflect the purpose of the rule. Second, the Company is clarifying that the subject of the billing reviews contemplated by the rule include customer usage in addition to billing demands. Third, the resulting billing/rate revisions now include changes to customer consumption to align with actual practice. The remaining changes to this section are minor housekeeping items.

Q. What changes is the Company proposing to Rule 16-c "Change in Rate" and Rule 16-d "Billing During Periods of Construction or Emergency" in the tariff?

A. The Company is revising Rules 16-c and 16-d to better align with the requirement in 66 Pa. C.S. § 1303 that utilities compute bills under the most advantageous rate to customers who qualify for more than one rate, after actual notice of service conditions.

Q. What tariff changes are being sponsored by Mr. Sorber?

A. Mr. Sorber is sponsoring tariff changes associated with Rule 1-c, certain outdoor lighting provisions, and Rate LP. These tariff sections are discussed in UGI Electric Statement No. 4.

Q. Are any other tariff changes being proposed by the Company?

A. The Company has proposed other, less substantive, changes to the tariff that are listed on page 2, List of Changes, of UGI Electric Exhibit F – Proposed Tariff. The Company also is making minor changes to the Electric Generation Supplier Coordination Tariff No. 2S.

Q. Does this conclude your testimony?

A. Yes.

UGI ELECTRIC

EXHIBIT SAE-1

Sherry Epler

Senior Manager, Tariff & Supplier Administration

<u>Work Experience</u>

<u>UGI Utilities, Inc., Denver, PA</u>

November 2019 – Present	Senior Manager, Tariff & Supplier Administration
2018 – November 2019	Manager, Revenue/Sales & Choice Administration

<u>UGI Utilities, Inc., Reading, PA</u>

2000 – 2018	Rates Analyst – I/II/Sr/Principal (Progressive Positions)
1997 – 2000	Data and Expense Analyst – Residential Marketing
1990 – 1997	Staff Accountant – Supply Accounting
1989 – 1990	Accounting Assistant, Supply – Accounting
1988 – 1989	Accounting Assistant, Rates & Budgets – Accounting
1986 - 1988	Accounting Assistant B – Accounting

<u>Education</u>

Bachelor of Science, Accounting, Albright College, 1995

Associate of Science, Business Administration, Pennsylvania State University, 1986

<u>Previous testimony provided before the Pennsylvania Public Utility Commission</u>:

Docket No. R-2021-3023618	UGI Electric Base Rate Case
Docket No. R-2021-3030218	UGI Gas Base Rate Case

UGI ELECTRIC

EXHIBIT SAE-2

UGI Utilities Inc. - Electric Division
15 Year Normal Heating Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average
Jan	1,282	932	1,034	1,084	1,347	1,217	1,285	1,042	1,086	1,336	1,268	1,140	992	1,210	1,188	1,163
Feb	989	979	1,226	1,008	949	1,046	1,008	851	1,013	1,136	1,309	924	757	824	953	998
Mar	1,027	862	899	891	800	685	905	514	940	1,039	996	623	938	955	872	863
Apr	402	437	598	383	429	348	463	496	462	500	446	495	289	628	371	450
May	296	221	167	309	193	171	148	85	201	157	94	236	225	87	145	182
Jun	16	66	25	25	47	28	29	50	25	10	25	26	41	26	26	31
Jul	0	0	16	0	9	6	0	0	2	1	0	0	0	0	0	2
Aug	0	7	25	15	9	6	6	3	11	9	0	0	19	0	3	8
Sep	33	148	80	98	140	83	81	126	158	106	38	60	94	82	49	92
Oct	397	466	236	499	491	406	419	350	334	302	390	352	224	413	302	372
Nov	626	581	751	731	591	695	567	805	789	761	509	623	701	812	798	689
Dec	1,163	819	1,047	1,034	1,094	1,192	886	898	1,037	909	638	996	1,108	933	961	981
Totals	6,231	5,518	6,104	6,077	6,099	5,883	5,797	5,220	6,058	6,266	5,713	5,475	5,388	5,970	5,668	5,831

UGI Utilities Inc. - Electric Division
15 Year Normal Cooling Degree Days (2005-2019)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	15 Year Average
Jan	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Apr	6	0	4	5	41	15	14	7	4	6	0	1	15	4	7	9
May	10	32	54	9	19	80	61	72	56	30	143	69	35	77	32	52
Jun	230	92	129	154	60	183	116	127	133	152	153	151	161	117	113	138
Jul	312	264	177	224	97	305	304	308	311	214	244	326	244	261	320	261
Aug	306	175	205	86	157	209	133	194	147	139	210	290	140	262	196	190
Sep	119	8	94	71	9	91	71	61	60	71	134	117	102	119	79	80
Oct	6	0	41	0	0	0	0	2	14	9	0	9	37	28	14	11
Nov	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
Dec	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals	989	571	704	549	383	883	699	771	725	621	885	963	734	868	761	740

UGI ELECTRIC

EXHIBIT SAE-3

UGI Utilities Inc. - Electric Division
Customer Counts at Year End September

Rate	Sept 1995	Sept 2017	Sept 2018	Sept 2019	Sept 2020	Sept 2021	Sept 2022	Sept 2023	Sept 2024
Res-General	42,920	44,014	44,024	44,104	44,301	44,237	44,253	44,319	44,335
Res-Heating	10,389	10,341	10,372	10,347	10,415	10,448	10,532	10,586	10,661
Com-General	5,872	7,142	7,179	7,239	7,294	7,302	7,292	7,346	7,384
Com-Heating	585	336	338	337	331	327	329	331	331
Ind-General	136	118	118	115	117	121	120	121	121
Ind-Heating	45	35	35	35	35	35	35	35	35
Public St & Hwy Lighting	51	54	53	54	53	53	55	54	54
Other	5	7	7	7	7	7	7	7	7
Sales for Resale	2	3	3	3	3	3	3	3	3
Total	60,005	62,050	62,129	62,241	62,556	62,533	62,626	62,802	62,931

Note: Excludes unmetered Lighting

UGI ELECTRIC

EXHIBIT SAE-4(a) – SAE-4(e)

UGI Utilities, Inc.- Electric Division
Fully Projected Future Test Year 2024 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2024	1,019,988	144,199	41,853	
Adjustment for Customer Changes	5,393	912	167	UGI Electric Exhibit SAE-4(b)
Adjustment for Normalized Use/Customer	30,549	5,513	1,179	UGI Electric Exhibit SAE-4(c)
Adjustment for STAS		1	0	UGI Electric Exhibit SAE-4(d)
Adjustment for DSIC		963	906	UGI Electric Exhibit SAE-4(e)
Fully Projected Future Test Year 2024	1,055,931	151,588	44,105	

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Customers in Test Year 2024 (Unadjusted)	44,002	10,431	4,852	1,781	61,066
2	Future Test Year 2024 Customers (Fully Adjusted)	44,034	10,581	4,868	1,841	61,324
3	Change in Customers during Future Test Year 2024	32	150	16	60	258
4	Total UPC (Unadjusted)-kWh	8,981	17,374	4,879	40,358	71,592
5	Annualization Adjustment for Sales-MWh	287	2,606	78	2,421	5,393
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.1802	$ 0.1802	$ 0.1827	$ 0.1554	
7	USP unit rate	$ 0.0115	$ 0.0115	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.0006	$ 0.0006	$ 0.0013	$ 0.0013	
9	GSR-1 unit rate	$ 0.1290	$ 0.1290	$ 0.1290	$ 0.1290	
10	Distribution unit rate (margin plus GRT)	$ 0.0391	$ 0.0391	$ 0.0524	$ 0.0250	
11	Revenue Adjustment (L5 * L6)	$ 52	$ 470	$ 14	$ 376	$ 912
12	USP Adjustment (L5 * L7)	$ 3	$ 30	$ -	$ -	$ 33
13	EEC Adjustment (L5 * L8)	$ 0	$ 2	$ 0	$ 3	$ 5
14	GSR Adjustment (L5 * L9)	$ 37	$ 336	$ 10	$ 312	$ 696
15	Distribution Adjustment (L5 * L10)	$ 11	$ 102	$ 4	$ 61	$ 178
16	Margin Adjustment (L15 less GRT)	$ 11	$ 96	$ 4	$ 57	$ 167

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

	[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.7665	0.5411	3.0174	0.2109	
DD Variance (to 15 Year normal)	349	349	349	349	
kWh/customer adjustment (L1 * L2)	617	189	1,053	74	
Customers FY24 (fully adjusted)	44,034	10,581	4,868	1,841	
Normalizing Adj (MWh) (L3 * L4)/1000	27,153	1,999	5,127	136	34,414
Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
Revenue Adjustment (L5 * L6)	$ 4,892	$ 360	$ 937	$ 21	$ 6,210
USP Adjustment (L5 * L7)	$ 312	$ 23	$ -	$ -	$ 335
EEC Adjustment (L5 * L8)	$ 16	$ 1	$ 7	$ 0	$ 24
GSR Adjustment (L5 * L9)	$ 3,503	$ 258	$ 662	$ 17	$ 4,440
Distribution Adjustment (L5 * L10)	$ 1,061	$ 78	$ 269	$ 3	$ 1,411
Margin Adjustment (L15 less GRT)	$ 998	$ 73	$ 253	$ 3	$ 1,328
Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.3442	0.3692	0.6874	0.0848	
DD Variance (to 15 Year normal)	(171)	(171)	(171)	(171)	
kWh/customer adjustment (L17 * L18)	(59)	(63)	(118)	(15)	
Customers FY24 (fully adjusted)	44,034	10,581	4,868	1,841	
Normalizing Adj (MWh) (L19 * L20)/1000	(2,596)	(669)	(573)	(27)	(3,865)
Total Revenue unit rate (L23+L24+L25+L26)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
Revenue Adjustment (L21 * L22)	$ (468)	$ (121)	$ (105)	$ (4)	$ (697)
USP Adjustment (L21 * L23)	$ (30)	$ (8)	$ -	$ -	$ (38)
EEC Adjustment (L21 * L24)	$ (2)	$ (0)	$ (1)	$ (0)	$ (3)
GSR Adjustment (L21 * L25)	$ (335)	$ (86)	$ (74)	$ (3)	$ (499)
Distribution Adjustment (L21 * L26)	$ (101)	$ (26)	$ (30)	$ (1)	$ (158)
Margin Adjustment (L31 less GRT)	$ (95)	$ (25)	$ (28)	$ (1)	$ (149)
Total Adjustment Summary-FY24					
Normalizing Adj (MWh) (L5+L21)	24,557	1,329	4,554	109	30,549
Total Revenue Adjustment (L11+L27)	$ 4,425	$ 240	$ 832	$ 17	$ 5,513
Total USP Adjustment (L12+L28)	$ 282	$ 15	$ -	$ -	$ 298
Total EEC Adjustment (L13+L29)	$ 14	$ 1	$ 6	$ 0	$ 21
Total GSR Adjustment(L14+L30)	$ 3,168	$ 172	$ 588	$ 14	$ 3,941
Total Distribution Adjustment(L15+L31)	$ 959	$ 52	$ 239	$ 3	$ 1,253
Total Margin Adjustment (L16+L32)	$ 903	$ 49	$ 224	$ 3	$ 1,179

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	DSIC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
						0.01%	0.01%	
Residential	$ 111,365	$ 521	$ 4,664	$ 703	$ 117,254	$ 12	$ 11	$ 1
Commercial & Industrial	$ 32,037	$ 391	$ 849	$ 249	$ 33,526	$ 3	$ 3	$ 0
Public Streets & Highway Lighting	$ 748	$ -		$ 9	$ 758	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 19	$ -		$ 0	$ 19	$ 0	$ 0	$ 0
Sales for Resale	$ 16	$ -		$ 0	$ 16	$ 0	$ 0	$ 0
Total	$ 144,185	$ 912	$ 5,513	$ 963	$151,572	$ 15	$ 14	$ 1

UGI Utilities, Inc.- Electric Division
Fully Projected Future Period- 12 Months Ended September 30, 2024
($ in Thousands)

Adjustment for DSIC

	Unadjusted Budget DSIC Revenue @3.24%	Adjusted Budget DSIC Revenue @ 5%	DSIC Revenue Adjustment	GRT on DISC Adjustment	DSIC Margin Adjustment
Residential	$ 1,159	$ 1,862	$ 703	$ (42)	$ 662
Commercial & Industrial	$ 465	$ 714	$ 249	$ (15)	$ 235
Public Streets & Highway Lighting	$ 18	$ 27	$ 9	$ (1)	$ 9
Other Sales to Public Authorities	$ 1	$ 1	$ 0	$ (0)	$ 0
Sales for Resale	$ 0	$ 0	$ 0	$ (0)	$ 0
Total	$ 1,642	$ 2,605	$ 963	$ (57)	$ 906

UGI ELECTRIC

EXHIBIT SAE-5(a) – SAE-5(d)

UGI Utilities, Inc.- Electric Division
Future Test Year 2023 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Budget 2023	1,001,278	140,115	40,243	
Adjustment for Customer Changes	2,692	455	84	UGI Electric Exhibit SAE-5(b)
Adjustment for Normalized Use/Customer	26,225	4,730	1,008	UGI Electric Exhibit SAE-5(c)
Adjustment for STAS		1	0	UGI Electric Exhibit SAE-5(d)
Future Test Year 2023	1,030,195	145,301	41,334	

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Customers in Test Year 2023 (Unadjusted)	44,002	10,431	4,852	1,781	61,066
2	Future Test Year 2023 Customers (Fully Adjusted)	44,018	10,506	4,860	1,811	61,195
3	Change in Customers during Future Test Year 2023	16	75	8	30	129
4	Total UPC (Unadjusted)-kWh	8,976	17,356	4,876	40,273	71,481
5	Annualization Adjustment for Sales-MWh	144	1,302	39	1,208	2,692
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	0.18018	0.18018	0.18271	0.15539	
7	USP unit rate	0.0115	0.0115	0.00000	0.00000	
8	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
9	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
10	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
11	Revenue Adjustment (L5 * L6)	$ 26	$ 235	$ 7	$ 188	$ 455
12	USP Adjustment (L5 * L7)	$ 2	$ 15	$ -	$ -	$ 17
13	EEC Adjustment (L5 * L8)	$ 0	$ 1	$ 0	$ 2	$ 2
14	GSR Adjustment (L5 * L9)	$ 19	$ 168	$ 5	$ 156	$ 347
15	Distribution Adjustment (L5 * L10)	$ 6	$ 51	$ 2	$ 30	$ 89
16	Margin Adjustment (L15 less GRT)	$ 5	$ 48	$ 2	$ 28	$ 84

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.5866	0.5084	2.5523	0.3211	
2	DD Variance (to 15 Year normal)	349	349	349	349	
3	kWh/customer adjustment (L1 * L2)	554	177	891	112	
4	Customers FY23 (fully adjusted)	44,018	10,506	4,860	1,811	
5	Normalizing Adj (MWh) (L3 * L4)/1000	24,378	1,864	4,330	203	30,776
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	0.18018	0.18018	0.18271	0.15539	
7	USP unit rate	0.0115	0.0115	0.00000	0.00000	
8	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
9	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
10	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
11	Revenue Adjustment (L5 * L6)	$ 4,393	$ 336	$ 791	$ 32	$ 5,551
12	USP Adjustment (L5 * L7)	$ 280	$ 21	$ -	$ -	$ 302
13	EEC Adjustment (L5 * L8)	$ 14	$ 1	$ 6	$ 0	$ 21
14	GSR Adjustment (L5 * L9)	$ 3,145	$ 241	$ 559	$ 26	$ 3,971
15	Distribution Adjustment (L5 * L10)	$ 952	$ 73	$ 227	$ 5	$ 1,257
16	Margin Adjustment (L15 less GRT)	$ 896	$ 69	$ 213	$ 5	$ 1,183
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.4072	0.4394	0.7906	0.1057	
18	DD Variance (to 15 Year normal)	(171)	(171)	(171)	(171)	
19	kWh/customer adjustment (L17 * L18)	(70)	(75)	(135)	(18)	
20	Customers FY23 (fully adjusted)	44,018	10,506	4,860	1,811	
21	Normalizing Adj (MWh) (L19 * L20)/1000	(3,070)	(791)	(658)	(33)	(4,551)
22	Total Revenue unit rate (L23+L24+L25+L26)	0.18018	0.18018	0.18271	0.15539	
23	USP unit rate	0.0115	0.0115	0.00000	0.00000	
24	EEC-Class 1 & Class 2 unit rate	0.00059	0.00059	0.00132	0.00132	
25	GSR-1 unit rate	0.12902	0.12902	0.12902	0.12902	
26	Distribution unit rate (margin plus GRT)	0.03907	0.03907	0.05237	0.02505	
27	Revenue Adjustment (L21 * L22)	$ (553)	$ (142)	$ (120)	$ (5)	$ (821)
28	USP Adjustment (L21 * L23)	$ (35)	$ (9)	$ -	$ -	$ (44)
29	EEC Adjustment (L21 * L24)	$ (2)	$ (0)	$ (1)	$ (0)	$ (3)
30	GSR Adjustment (L21 * L25)	$ (396)	$ (102)	$ (85)	$ (4)	$ (587)
31	Distribution Adjustment (L21 * L26)	$ (120)	$ (31)	$ (34)	$ (1)	$ (186)
32	Margin Adjustment (L31 less GRT)	$ (113)	$ (29)	$ (32)	$ (1)	$ (175)
33	Total Adjustment Summary-FY23					
34	Normalizing Adj (MWh) (L5+L21)	21,309	1,074	3,672	170	26,225
35	Total Revenue Adjustment (L11+L27)	$ 3,839	$ 193	$ 671	$ 26	$ 4,730
36	Total USP Adjustment (L12+L28)	$ 245	$ 12	$ -	$ -	$ 257
37	Total EEC Adjustment (L13+L29)	$ 13	$ 1	$ 5	$ 0	$ 18
38	Total GSR Adjustment(L14+L30)	$ 2,749	$ 139	$ 474	$ 22	$ 3,383
39	Total Distribution Adjustment(L15+L31)	$ 833	$ 42	$ 192	$ 4	$ 1,071
40	Total Margin Adjustment (L16+L32)	$ 783	$ 39	$ 181	$ 4	$ 1,008

UGI Utilities, Inc.- Electric Division
Future Period- 12 Months Ended September 30, 2023
($ in Thousands)

Adjustment for STAS

	Unadjusted Budget Revenue Excluding STAS	Customer Adj	UPC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Dec 1 Rate	STAS Revenue @ Budget Rate	STAS Adjustment
					0.01%	0.01%	
Residential	$ 110,320	$ 260	$ 4,033	$ 114,613	$ 11	$ 11	$ 0
Commercial & Industrial	$ 29,015	$ 195	$ 697	$ 29,907	$ 3	$ 3	$ 0
Public Streets & Highway Lighting	$ 734	$ -		$ 734	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 18	$ -		$ 18	$ 0	$ 0	$ -
Sales for Resale	$ 15	$ -		$ 15	$ 0	$ 0	$ (0)
Total	$ 140,101	$ 455	$ 4,730	$145,287	$ 15	$ 14	$ 1

UGI ELECTRIC

EXHIBIT SAE-6(a) – SAE-6(g)

UGI Utilities, Inc.- Electric Division
Historic Test Year 2022 Sales and Revenues
Summary of Adjustments

	Sales (000's) MWh	Revenues ($000's)	Margin ($000's)	Reference
Actual 2022	997,113	124,822	38,876	
Adjustment for Customer Changes	46	7	(1)	UGI Electric Exhibit SAE-6(b)
Adjustment for Normalized Use/Customer	17,961	3,243	699	UGI Electric Exhibit SAE-6(c)
Adjustment for GSR-1		22,191	0	UGI Electric Exhibit SAE-6(d)
Adjustment for USP		1,417	0	UGI Electric Exhibit SAE-6(e)
Adjustment for STAS		5	0	UGI Electric Exhibit SAE-6(f)
Adjustment for EEC		(60)		UGI Electric Exhibit SAE-6(g)
Adjusted Historic Test Year 2022	1,015,120	151,625	39,574	

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Customer Changes
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Average Effective Customers in Historic Year	44,003	10,430	4,853	1,781	61,067
2	Number of Customers at End of Year	43,963	10,462	4,816	1,782	61,023
3	Change in Customers during Historic Year 2022	(40)	32	(37)	1	(44)
4	Total UPC (Unadjusted)-kWh	8,912	17,205	5,114	41,619	
5	Annualization Adjustment for Sales-MWh	(356)	551	(189)	42	46
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
7	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
9	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
10	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
11	Revenue Adjustment (L5 * L6)	$ (64)	$ 99	$ (35)	$ 6	$ 7
12	USP Adjustment (L5 * L7)	$ (4)	$ 6	$ -	$ -	$ 2
13	EEC Adjustment (L5 * L8)	$ (0)	$ 0	$ (0)	$ 0	$ (0)
14	GSR Adjustment (L5 * L9)	$ (46)	$ 71	$ (24)	$ 5	$ 6
15	Distribution Adjustment (L5 * L10)	$ (14)	$ 22	$ (10)	$ 1	$ (1)
16	Margin Adjustment (L15 less GRT)	$ (13)	$ 20	$ (9)	$ 1	$ (1)

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for Usage per Customer
Rate R General, Rate R Heating, Rate GS-1 Com-Gen, Rate GS-4 Com-Gen
GSR subgroups only

Line #		[1] Rate R General	[2] Rate R Heating	[3] Rate GS-1 Com-Gen	[4] Rate GS-4 Com-Gen	[5] Total
1	Heating Sensitivity/HDD/cust (kWh/DD/cust)	1.9331	0.5136	3.3826	0.2627	
2	DD Variance (to 15 Year normal)	247	247	247	247	
3	kWh/customer adjustment (L1 * L2)	478	127	836	65	
4	Customers FY22 (fully adjusted)	43,963	10,462	4,816	1,782	
5	Normalizing Adj (MWh) (L3 * L4)/1000	20,997	1,328	4,025	116	26,465
6	Total Revenue unit rate (L7+L8+L9+L10+L11)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
7	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
8	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
9	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
10	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
11	Revenue Adjustment (L5 * L6)	$ 3,783	$ 239	$ 735	$ 18	$ 4,776
12	USP Adjustment (L5 * L7)	$ 241	$ 15	$ -	$ -	$ 257
13	EEC Adjustment (L5 * L8)	$ 12	$ 1	$ 5	$ 0	$ 19
14	GSR Adjustment (L5 * L9)	$ 2,709	$ 171	$ 519	$ 15	$ 3,415
15	Distribution Adjustment (L5 * L10)	$ 820	$ 52	$ 211	$ 3	$ 1,086
16	Margin Adjustment (L15 less GRT)	$ 772	$ 49	$ 198	$ 3	$ 1,022
17	Cooling Sensitivity/CDD/cust (kWh/DD/cust)	0.9088	0.7596	1.189	0.2499	
18	DD Variance (to 15 Year normal)	(157)	(157)	(157)	(157)	
19	kWh/customer adjustment (L17 * L18)	(143)	(119)	(187)	(39)	
20	Customers FY22 (fully adjusted)	43,963	10,462	4,816	1,782	
21	Normalizing Adj (MWh) (L19 * L20)/1000	(6,283)	(1,250)	(901)	(70)	(8,504)
22	Total Revenue unit rate (L23+L24+L25+L26)	$ 0.18018	$ 0.18018	$ 0.18271	$ 0.15539	
23	USP unit rate	$ 0.01150	$ 0.01150	$ -	$ -	
24	EEC-Class 1 & Class 2 unit rate	$ 0.00059	$ 0.00059	$ 0.00132	$ 0.00132	
25	GSR-1 unit rate	$ 0.12902	$ 0.12902	$ 0.12902	$ 0.12902	
26	Distribution unit rate (margin plus GRT)	$ 0.03907	$ 0.03907	$ 0.05237	$ 0.02505	
27	Revenue Adjustment (L21 * L22)	$ (1,132)	$ (225)	$ (165)	$ (11)	$ (1,533)
28	USP Adjustment (L21 * L23)	$ (72)	$ (14)	$ -	$ -	$ (87)
29	EEC Adjustment (L21 * L24)	$ (4)	$ (1)	$ (1)	$ (0)	$ (6)
30	GSR Adjustment (L21 * L25)	$ (811)	$ (161)	$ (116)	$ (9)	$ (1,097)
31	Distribution Adjustment (L21 * L26)	$ (245)	$ (49)	$ (47)	$ (2)	$ (343)
32	Margin Adjustment (L31 less GRT)	$ (231)	$ (46)	$ (44)	$ (2)	$ (323)
33	Total Adjustment Summary-FY22					
34	Normalizing Adj (MWh) (L5+L21)	14,714	78	3,124	46	17,961
35	Total Revenue Adjustment (L11+L27)	$ 2,651	$ 14	$ 571	$ 7	$ 3,243
36	Total USP Adjustment (L12+L28)	$ 169	$ 1	$ -	$ -	$ 170
37	Total EEC Adjustment (L13+L29)	$ 9	$ 0	$ 4	$ 0	$ 13
38	Total GSR Adjustment(L14+L30)	$ 1,898	$ 10	$ 403	$ 6	$ 2,317
39	Total Distribution Adjustment(L15+L31)	$ 575	$ 3	$ 164	$ 1	$ 743
40	Total Margin Adjustment (L16+L32)	$ 541	$ 3	$ 154	$ 1	$ 699

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for GSR-1

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Actual GSR-1 Rate FY 22	$0.06218	$0.06218	$0.09005	$0.09005	$0.09005	$0.08853	$0.08853	$0.08853	$0.12902	$0.12902	$0.12902	$0.12902	
HTY 2022 GSR-1 Sep 1 Rate	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	$0.12902	
GSR-1 Rate Variance	$0.06684	$0.06684	$0.03897	$0.03897	$0.03897	$0.04049	$0.04049	$0.04049	$0.00000	$0.00000	$0.00000	$0.00000	
Total GSR-1 Volumes-MWh	56,818	57,956	69,575	77,000	63,269	64,025	45,354	47,252	50,314	66,113	60,907	39,607	698,188
GSR-1 Revenue Adjustment	$3,798	$3,874	$2,711	$3,001	$2,466	$2,592	$1,836	$1,913	$0	$0	$0	$0	$22,191

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for USP

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Historic Period FY22 USP Rate	$0.00565	$0.00565	$0.00865	$0.00865	$0.00865	$0.00762	$0.00762	$0.00762	$0.01150	$0.01150	$0.01150	$0.01150	
HTY 2022 USP Sep 1 Rate	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	$0.01150	
USP Rate Variance	$0.00585	$0.00585	$0.00285	$0.00285	$0.00285	$0.00388	$0.00388	$0.00388	$0.00000	$0.00000	$0.00000	$0.00000	
Total Rate R Volumes-MWh	38,033	48,873	60,227	66,679	54,098	53,971	37,576	38,892	41,203	54,811	49,633	32,051	576,049
Total Rate R excl CAP Volumes-MWh	35,218	45,257	55,771	61,745	50,095	49,977	34,795	36,014	38,154	50,755	45,961	29,680	533,421
USP Rate Revenue Variance	$206	$265	$159	$176	$143	$194	$135	$140	$0	$0	$0	$0	$1,417

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for STAS

	Actual Revenue Excluding STAS	Customer Adj	UPC Adj	GSR-1 Adj	USP Adj	EEC Adj	Revised Revenue Excluding STAS	STAS Revenue @ Sep 1 Rate	STAS Revenue @ FY 22	STAS Adjustment
								0.01%	0.01%	
Residential	$ 89,004	$ 24	$ 2,665	$ 18,015	$ 1,417	$ (120)	$ 111,006	$ 11	$ 7	$ 4
Commercial & Industrial	$ 34,805	$ (28)	$ 578	$ 4,110	$ -	$ 63	$ 39,527	$ 4	$ 3	$ 1
Public Streets & Highway Lighting	$ 982	$ -		$ 62	$ -	$ (3)	$ 1,042	$ 0	$ 0	$ 0
Other Sales to Public Authorities	$ 21	$ -		$ -	$ -	$ (1)	$ 20	$ 0	$ 0	$ 0
Sales for Resale	$ (0)	$ -		$ 4	$ -	$ (0)	$ 4	$ 0	$ 0	$ (0)
Total	$ 124,812	$ (4)	$ 3,243	$ 22,191	$1,417	($60)	$151,599	$ 15	$ 10	$ 5

UGI Utilities, Inc.- Electric Division
Historic Period- 12 Months Ended September 30, 2022
($ in Thousands)

Adjustment for EEC

	OCT 2021	NOV 2021	DEC 2021	JAN 2022	FEB 2022	MAR 2022	APR 2022	MAY 2022	JUN 2022	JUL 2022	AUG 2022	SEP 2022	TOTAL
Historic EEC-Class 1 Actual Rates FY 22	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00059	
Historic Year 2022 EEC-Class 1 Rate Effective Sept 1	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	$0.00059	
EEC-Class 1 Rate Variance	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	($0.00022)	$0.00000	
Total EEC-Class 1 Volumes	38,184	49,039	60,404	66,860	54,244	54,128	37,695	39,016	41,335	54,968	49,782	32,161	577,816
Total EEC-Class 1 Revenue Adjustment	($8)	($11)	($13)	($15)	($12)	($12)	($8)	($9)	($9)	($12)	($11)	$0	($120)
Historic EEC-Class 2 Actual Rates FY 22	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00132	
Historic Year 2022 EEC-Class 2 Rate Effective Sept 1	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	$0.00132	
EEC-Class 2 Rate Variance	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	($0.00071)	$0.00000	
Total EEC-Class 2 Volumes	11,279	12,369	12,706	13,963	12,147	13,559	10,615	11,036	12,104	14,837	14,368	9,931	148,913
Total EEC-Class 2 Revenue Adjustment	($8)	($9)	($9)	($10)	($9)	($10)	($8)	($8)	($9)	($11)	($10)	$0	($99)
Historic EEC-Class 3 Actual Rates FY 22	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00138	$0.00203	
Historic Year 2022 EEC-Class 3 Rate Effective Sept 1	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	$0.00203	
EEC-Class 3 Rate Variance	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00065	$0.00000	
Total EEC-Class 3 Volumes	20,429	20,707	17,062	27,690	23,818	17,622	24,036	21,318	22,658	22,854	25,455	26,735	270,384
Total EEC-Class 3 Revenue Adjustment	$13	$13	$11	$18	$15	$11	$16	$14	$15	$15	$17	$0	$158
Total EEC Revenue Adjustment	($3)	($6)	($11)	($7)	($5)	($10)	($0)	($3)	($3)	($8)	($5)	$0	($60)