BOOK III

UGI UTILITIES, INC. – GAS DIVISION

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI GAS STATEMENT NO. 1 – PAUL J. SZYKMAN
UGI GAS STATEMENT NO. 2 – HANS G. BELL
UGI GAS STATEMENT NO. 3 – STEPHEN F. ANZALDO
UGI GAS STATEMENT NO. 4 – MEGAN MATTERN
UGI GAS STATEMENT NO. 5 – PAUL R. MOUL
UGI GAS STATEMENT NO. 6 – PAUL R. HERBERT
UGI GAS STATEMENT NO. 7 – JOHN F. WIEDMAYER

ORIGINAL TARIFFS
UGI UTILITIES, INC. – GAS DIVISION - PA P.U.C. NOS. 7-7S

DOCKET NO. R-2018-3006814

Issued: January 28, 2019 **Effective: March 29, 2019**

UGI GAS STATEMENT NO. 1 – PAUL J. SZYKMAN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 1

Direct Testimony of
Paul J. Szykman

Topics Addressed:	**Rate Filing Overview and Need for Rate Relief** **Merger of Rate Districts into Unified Tariff** **Improvement Initiatives UGI-1 & UNITE** **Interruptible Revenue Proposals** **Management Performance**

Dated: January 28, 2019

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Paul J. Szykman. My business address is 1 UGI Drive, Denver, PA 17517.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as its Chief Regulatory Officer.

Q. Please briefly describe your responsibilities in that capacity.

A. As Chief Regulatory Officer, I am responsible for all rate, governmental affairs and regulatory compliance activities for UGI Utilities, Inc. – Gas Division ("UGI Gas") and UGI Utilities, Inc. – Electric Division ("UGI Electric"). For the rates component, I oversee the areas of sales and revenue forecasting, tariff administration and compliance, Choice administration and compliance, rate administration, Section 1307(f) purchased gas cost ("PGC") filings, electric provider of last resort ("POLR") filings, Section 1307(e) filings, base rate cases, and UGI's energy management information technology systems. My government relations responsibilities include managing the development and implementation of the Company's strategies in federal and state legislative and regulatory arenas. My regulatory compliance responsibilities cover a broad range of oversight and compliance for the state and federal jurisdictional activities of UGI. Prior to my role as Chief Regulatory Officer, I was Vice President – Rates & Government Relations and Vice President & General Manager – Electric Utilities. In my current role I report directly to the President and Chief Executive Officer of UGI.

Q. What is your educational and professional background?

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

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit PJS-1 contains a list of those proceedings.

II. PURPOSE OF TESTIMONY

Q. Please describe the purpose of your testimony in this proceeding.

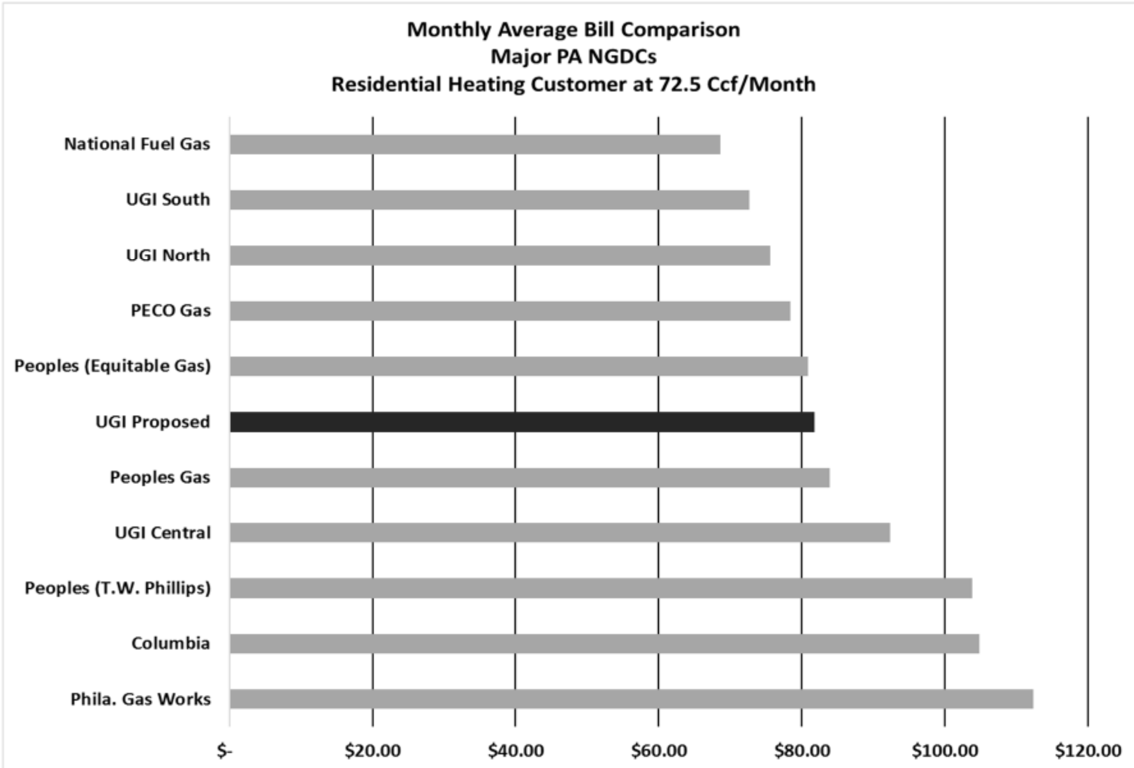
A. My testimony addresses several issues. First, I present an overview of the rate filing, including a brief explanation of the reasons for rate relief and an outline of the testimony of each witness in this proceeding. Second, I will describe the recent merger of UGI's former utility subsidiaries into UGI Gas's current three rate districts, and provide an overview of UGI Gas's proposal in this proceeding to merge these three rate districts and establish a common unified tariff. Third, I describe UGI-1, an initiative designed to align UGI's people, processes and tools across the utility, and UGI's Next Information Technology Enterprise ("UNITE") Initiative, which is UGI's ongoing effort to develop and implement next generation technology solutions. Fourth, I discuss UGI Gas's proposed ratemaking treatment of interruptible service revenues. Lastly, I will summarize UGI Gas's focus on management, its success in improving management performance, and how management performance should be recognized in this case.

As further explained below, UGI Gas's management continues to improve service to customers through various initiatives, including, but not limited to: the UGI-1 initiative focused on resource alignment; the UNITE system improvement initiative addressing system modernization; an accelerated infrastructure replacement plan anchored by Long

Term Infrastructure Improvement Plans ("LTIIPs"); an innovative expansion and extension program targeting unserved and underserved areas; supporting customer growth rates which are highest in the Commonwealth; nationally recognized customer satisfaction by J.D. Power; recent funding increases for universal services offerings; energy efficiency and conservation plans promoting efficient energy utilization and environmental benefits; flexible customer-focused rate alternatives, *i.e.*, the Technology and Economic Development ("TED") Rider, supporting natural gas utilization; and a strong safety focus via a number of continuous safety improvement initiatives. In summary, UGI Gas offers excellent service to customers at reasonable rates.

A comparison of average residential heating bills, shown in Table 1 below, illustrates that UGI Gas's current distribution rates compare favorably to the rates of other major natural gas distribution companies in the Commonwealth, and will remain so, even at the full increase of proposed rates.

Table 1. – Residential Heating Bill Comparison



It is also important to note that the Company has focused in recent years on a continued restructuring of its natural gas supply portfolios in order to maximize the benefits associated with the Commonwealth's vast shale gas supply resources. Customer benefits associated with these activities are readily evident. Even with the rate changes proposed in this proceeding, the average residential heating customer bill will be significantly lower than just 10 years ago. Specifically, under the Company's proposal in this case, the average residential heating customer bills for UGI South, North and Central Rate Districts will be 52%, 38% and 35% lower, respectively, than 10 years ago.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI Gas Exhibit PJS-1 mentioned above, I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing. Specifically, I am sponsoring those schedules that were prepared by me or under my direction as identified in this filing.

III. RATE FILING OVERVIEW AND NEED FOR RATE RELIEF

Q. Please discuss UGI Gas's proposed rate relief request and the proposed major tariff and rate design changes.

A. UGI Gas is requesting an increase in its annual base rate operating revenues of $71.1 million, or 8.9 percent on a total revenue basis, with a proposed effective date of March 29, 2019. The base rate increase requested in this filing is based on a fully projected future test year ending September 30, 2020 ("FPFTY"). In addition, UGI Gas also proposes in this proceeding to:

- establish uniform distribution rates and purchased gas cost ("PGC") rates under a unified tariff in lieu of its current three rate district tariffs, including transportation service rates;
- establish uniform tariff rules under a unified tariff in lieu of its current three rate district tariffs, including uniform Choice and non-Choice transportation program rules;
- establish an expanded and unified Energy Efficiency and Conservation ("EE&C") Plan, designed to promote efficient use of natural gas across the entire UGI Gas service territory;
- implement a second phase of the Growth Extension Tariff ("GET Gas") pilot program;

- convert the TED Rider from a pilot to a permanent program and expand its applicability to the current Central Rate District;
- return certain additional benefits associated with the 2017 Tax Cut and Job Act ("TCJA") through the extension of the existing TCJA credit mechanism for an additional 12 month period;
- establish an Extension and Expansion Fund ("EEF") through the targeted utilization of a portion of interruptible revenues; and,
- establish an incentive sharing mechanism which incentivizes the Company to maximize interruptible revenues.

Q. Why is UGI seeking a rate increase at this time?

A. UGI Gas continues to make significant system investments which are necessary to: serve new residential and commercial customers; connect customers converting to natural gas; continue the accelerated replacement of aging gas plant infrastructure; upgrade and improve system segments and modernize facilities; and install and upgrade supporting information technology systems, all as part of growing and maintaining a safe and reliable distribution system and providing quality customer service. As compared to current plant and base rate levels reflected in current rates, UGI Gas is projecting an increase of approximately $1.0 billion in gross plant and over $650 million in rate base through the FPFTY. UGI Gas's current rates will not provide it with a reasonable opportunity to earn its cost of capital on this increased rate base.

Also, UGI Gas's rate districts receive a return on and of certain portions of these investments through their Distribution System Improvement Charges ("DSIC"), but these charges cannot sustain the magnitude of the Company's capital investments into the future. The DSIC charge in the UGI Central Rate District has reached its established cap (caps are currently 7.5% of distribution revenues for the UGI North and Central Rate Districts, and 5% for the UGI South Rate District), and the DSIC charges in UGI Gas's other rate districts are projected to be at or near cap levels by the end of the FPFTY. Accordingly, the Company will be unable to earn a reasonable return on future investment amounts without base rate relief.

Other cost drivers adversely impact the Company's ability to earn a reasonable rate of return on its utility investment. Since the last base rate case for each of UGI Gas's current rate districts, UGI Gas has also adopted modest annual wage and salary adjustments and will continue to do so, where reasonable, and has experienced other general price increases for necessary products and services. Although UGI Gas has made major strides toward integrating its operations and has seen stable customer growth over time, the growth in operating and capital costs, along with experienced and anticipated changes in per customer usage, are projected at levels which will prevent UGI Gas from having a reasonable opportunity to earn a fair rate of return on its investment at present rates.

Specifically, as reflected in UGI Gas Exhibit A (Fully Projected), Schedule A-1, UGI Gas's operations are projected to produce an overall return on rate base of 6.20%, which equates to a return on common equity of only 7.41% for the twelve months ending September 30, 2020. As explained by UGI Gas witness Paul R. Moul (UGI Gas St. No. 5), those returns are not adequate based on applicable financial analysis and the risks confronted by UGI Gas. Unless UGI Gas receives the requested rate relief, those returns will continue to decline and potentially jeopardize UGI Gas's ability to attract the capital needed to make system investments that support enhancing the reach and capacity of its distribution system and replacing older, obsolete facilities, systems and equipment, each of which is necessary to ensure continued system reliability, safety, and customer service performance.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI Gas in this proceeding and the subject matter of their testimony.

A. In addition to my testimony, the following witnesses are providing testimony in support of the Company's rate request:

Hans G. Bell (UGI Gas St. No. 2) serves as Chief Operating Officer at UGI. His testimony provides an overview of UGI Gas's operations and natural gas system, its Commission-approved LTIIPs, and the impact of the LTIIP and other initiatives on system performance, safety, and reliability. Additionally, Mr. Bell discusses enhancements to UGI Gas's workplace safety program and the Company's various employee safety performance metrics. Finally, Mr. Bell addresses UGI Gas's efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where UGI Gas or corporate predecessors once owned and operated manufactured gas plants in connection with gas utility operations.

Stephen F. Anzaldo (UGI Gas St. No. 3) serves as Director of Rates & Regulatory Planning for UGI Gas. He addresses UGI Gas's budgeting process; operating revenues and expenses; compliance with Section 1301.1 of the Public Utility Code and the revenue requirement model supporting the Company's proposed rate increase (UGI Gas Exhibit A (Fully Projected)). Mr. Anzaldo also sponsors the revenue requirement models for the future and historic periods, UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic), respectively. In addition, Mr. Anzaldo supports the supplemental informational rate district revenue requirement models found in UGI Gas Exhibit G.

Megan Mattern (UGI Gas St. No. 4) serves as Controller at UGI. Ms. Mattern presents UGI Gas's rate base claim for the historic test year ended September 30, 2018 ("HTY"), future test year ending September 30, 2019 ("FTY"), and FPFTY. Ms. Mattern also addresses the impact of a new revenue accounting standard on budgeted revenue, an accounting adjustment associated with cloud-based technology services, accounting for UNITE Phase II costs, a proposed gas cost adjustment, and an expense adjustment related to the Company's fee-free ACH and credit card payment proposal.

Paul R. Moul (UGI Gas St. No. 5) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony supporting the Company's claimed capital structure, cost of debt, cost of common equity and overall fair rate of return. Schedules and workpapers supporting Mr. Moul's findings are set forth in UGI Gas Exhibit B.

Paul R. Herbert (UGI Gas St. No. 6) is President of Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Herbert prepared and sponsors UGI Gas's fully allocated cost of service study. These studies are contained in UGI Gas Exhibit D. Mr. Herbert also prepared the supplemental informational rate district fully allocated cost of service studies found in UGI Gas Exhibit H.

John F. Wiedmayer (UGI Gas St. No. 7) is Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports UGI Gas's claim for annual depreciation expense and the accumulated depreciation reserve. His studies are presented in UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic). These exhibits also include supplemental informational rate district depreciation data.

David E. Lahoff (UGI Gas St. No. 8) serves as Senior Manager – Tariff & Supplier Administration at UGI. Mr. Lahoff is responsible for all areas of UGI Gas's rate design and revenue allocation, except for certain interruptible revenue proposals, which I address below. Mr. Lahoff's testimony presents supporting sales and revenue adjustments for each tariff customer class, including related models and assumptions. He also addresses and sponsors related exhibits, including the proof of revenues and proposed rate design (UGI Gas Exhibit E - Proof of Revenues). Also, Mr. Lahoff provides detail supporting the Company's approach to revenue allocation and the reasonableness of both the impacts of the revenue allocation proposed by the Company as well as the rate district impacts related to the unification of distribution rates, purchased gas cost rates and rider rates.

In addition, Mr. Lahoff sponsors UGI Gas Exhibit F, which is proposed Original Tariff – Gas Pa. P.U.C. No. 7 ("Tariff No. 7"), which replaces the current tariffs of UGI Gas's three rate districts. Mr. Lahoff provides a summary of the proposed changes to the tariff rules, regulations, and rate schedules included in Tariff No. 7, and the proposed changes to the Choice Supplier Tariff, incorporated into Tariff No. 7 as Tariff No. 7-S. Mr. Lahoff also provides an explanation of the unification of the following rates and riders: State Tax Adjustment Surcharge, PGC Rate, DSIC, Gas Delivery Enhancement Rider, EE&C Rider, Merchant Function Rider, Gas Procurement Charge, Universal Service Program Rider ("USP Rider"), GET Gas Rider and modifications to the TCJA Temporary Rider. Mr. Lahoff also addresses tariff changes related to Customer Choice for UGI, including the pending expansion of UGI Gas's purchase of receivables program and the establishment of common surety requirements for Natural Gas Suppliers ("NGS").

Shaun M. Hart (UGI Gas St. No. 9) is UGI Gas's Senior Manager Major Accounts. He addresses UGI Gas's proposed continuation and expansion of its TED Rider, large customer account usage and revenue projections, implementation of the proposed EE&C Plan, proposed Phase II GET Gas pilot program (including reporting related to the GET Gas Phase I pilot), a proposal to expand daily metering, and the continuation of the excess requirement option.

Daniel V. Adamo (UGI Gas St. No. 10) is the Director – Customer Services at UGI Gas. Mr. Adamo addresses quality of service performance, the Universal Service and Energy Conservation Plan ("USECP"), the USP Rider and the Company's fee-free ACH and credit card payment proposal to facilitate electronic payment options for customers.

Nicole McKinney (UGI Gas St. No. 11) is a Principal Tax Analyst at UGI Gas. Ms. McKinney addresses various tax issues, including the Company's claim for federal and state income taxes, taxes other than income taxes, the calculation of the accumulated deferred income taxes ("ADIT") offset to rate base, the repairs allowance, the calculation of a hypothetical consolidated tax savings adjustment for purposes of Section 1031.1 of the Public Utility Code and the calculation of the TCJA benefit for the period January 2018 through June 2018, which is proposed to be returned to customers.

Angelina M. Borelli (UGI Gas St. No. 12) is the Director – Energy Supply and Planning at UGI Gas. Ms. Borelli describes UGI Gas's proposed unified Choice and Non-Choice transportation customer delivery rules. A number of these items were developed as a result of the collaborative held with natural gas suppliers and other interested parties in accordance with the terms of the Commission-approved settlement in UGI's recent merger proceeding.

Theodore M. Love (UGI Gas St. No. 13) is Senior Analyst of Green Energy Economics Group, Inc. Mr. Love presents and supports UGI Gas's proposed unified and expanded EE&C Plan. Mr. Love also provides the results of an analysis applying the total resource cost ("TRC") test.

IV. MERGER OF RATE DISTRICTS INTO UNIFIED TARIFF

Q. Please describe the recent merger involving UGI Gas.

A. Prior to October 1, 2018, UGI Gas had two wholly-owned subsidiaries which were Commission-certificated natural gas distribution companies ("NGDC"). Those subsidiaries were UGI Penn Natural Gas, Inc. ("UGI PNG") and UGI Central Penn Gas ("UGI CPG"). UGI PNG began its operations as a UGI company on August 24, 2006, the effective date of UGI Corporation's purchase of the natural gas distribution assets from the former PG Energy Division of Southern Union Company, as authorized by a

Commission Ordered entered on August 18, 2006, at Docket No. A-120011F200. UGI CPG, formerly PPL Gas Utilities Corporation, was acquired by UGI Gas effective October 1, 2008, as authorized by a Commission Order entered on August 21, 2008, at Docket Nos. A-2008-2034045 *et al*. On March 8, 2018, UGI Gas filed a petition with the Commission to merge UGI PNG and UGI CPG into UGI Gas, and to thereafter operate as three rate districts adopting the three former tariffs of UGI Gas, UGI PNG and UGI CPG, respectively. A Joint Petition for Approval of Settlement of All Issues ("Merger Settlement") was subsequently reached and submitted to the Commission, and in an Order entered on September 20, 2018 at Docket Nos. A-2018-3000381, A-2018-3000382 and A-2018-3000383 ("Merger Order"), the Commission approved the Merger Settlement with certain revisions not opposed by any party.

The merger was completed on October 1, 2018, and UGI Gas commenced operations under the three rate district structure described above. UGI Gas currently maintains: (a) three sets of base rates; (b) three gas supply portfolios; (c) three PGC rates; (d) three sets of rules applicable NGSs serving Choice and Non-Choice Suppliers, and (e) three rate district tariffs.

Q. Has UGI Gas undertaken any initiatives to better align the operation of its three rate districts?

A. Yes. UGI Gas's three rate districts have been operated under common management for some time even before the merger. Through the UGI-1 and UNITE initiatives discussed below, UGI Gas has adopted common tools, business processes and information systems to better align its operations. A significant advance in this effort was achieved in the fall of 2017, when UGI Gas established a new common customer information system, replacing two prior legacy systems, giving UGI a common information system platform to drive and support core business activities, enhance customer service performance and offerings and provide a technology platform capable of supporting future business needs. Furthermore, through a series of base rate cases, UGI Gas has largely aligned the rate structure and tariff provisions of the three rate districts to the extent possible given the need to maintain separate base rate and PGC rates and separate service territory-specific gas supply portfolios with related transportation delivery rules.

Q. Is UGI Gas proposing to maintain three separate rate districts in this proceeding?

A. No. Importantly, UGI Gas is proposing in this case to establish: (a) uniform base rates and associated surcharges and riders across its system; (b) a uniform PGC rate across its system to recover PGC costs from a consolidated, common supply portfolio; (c) a single price to compare across its system; (d) unified Choice Supplier rules, capacity release rules, sale and delivery requirements, as well as financial surety requirements; (e) unified Non-Choice Transportation customer delivery and balancing requirements based on system reliability requirements as opposed to rate district service territories; and (f) a uniform system-wide tariff.

I would note that as part of its Commission-approved Merger Settlement, UGI Gas agreed to undertake a collaborative process to establish proposed unified Choice and Non-Choice Transportation rules and to propose the adoption of such rules on or before February 28, 2018. The collaborative process and resulting proposal are described in the direct testimony of Ms. Borelli (UGI Gas St. No. 12), and are reflected in UGI Gas's proposed tariff (UGI Gas Exhibit F – Proposed).

Q. What are the benefits of the proposed consolidation?

A. From a customer perspective, eliminating separate rate districts will facilitate customer service and communications. UGI Gas's customer service representatives will now be trained on one tariff and one set of tariff rates in lieu of three. This will provide for more efficient and effective training and greater customer support. Customer bill inserts, customer notices, and Company press releases are additional examples of communication items which will now be uniformly communicated to customers in lieu of separate rate district versions. Moreover, unified rates will provide for a unified price-to-compare across the UGI Gas territory. This change will bring the benefits of expanded offerings by NGSs, who will now have the ready capability to expand their service offerings in uniform fashion across the entire UGI Gas territory. This benefit will also be enhanced by the Company's proposed expansion of its purchase of receivables ("POR") program to the UGI Gas North and Central Rate Districts. The POR program has seen significant NGS participation to-date in the UGI Gas South rate district and it is anticipated to be equally successful in expanded form; yielding greater NGS service offerings to customers. Customers will also ultimately benefit from the administrative efficiencies that will result from consolidation, and the increased options that should be available to UGI Gas in constructing future natural gas supply portfolios.

From a Choice Supplier perspective, an integrated gas supply portfolio will enable UGI Gas, as described in more detail in the testimony of Ms. Borelli (UGI Gas St. No. 12), to offer Choice Suppliers a common set of delivery standards when delivering gas to UGI Gas's system to meet daily delivery requirements. Choice Suppliers will be able to market products across a larger potential customer base with a unified price to compare, and achieve the operational efficiencies of a single delivery requirement. Choice

Suppliers should also benefit from UGI Gas's proposed expansion of its POR program to encompass its entire system, as noted in the testimony of Mr. Lahoff (UGI Gas St. No. 8). Again, UGI Gas's POR program has seen significant NGS participation to-date in the UGI Gas South rate district and it is anticipated to be equally successful in expanded form; yielding greater flexibility for NGSs to expand service offerings to, and within, the UGI Gas service territories. NGSs serving Non-Choice Transportation customers and Transportation customers procuring their own up-stream supplies will benefit, as described in more detail in Ms. Borelli's testimony (UGI Gas St. No. 12), from delivery service requirements tied to system capabilities and up-stream markets, rather than separate rate districts with separate gas supply portfolios. Since most Non-Choice Transportation customers receive service through NGS-operated pools that comply with nomination, delivery and balancing requirements on a pool-wide basis, this reduction in the number of disparate delivery service rules should reduce the number of pools that need to be separately managed and balanced by NGSs, providing for NGS operational efficiencies and Company administrative efficiencies.

From an operational and administrative perspective, UGI Gas will also benefit by avoiding the costs associated with separately managing and complying with the regulatory reporting and other requirements for three separate service territories and rate districts remaining after the merger. The elimination of the remaining triplicate rate district reporting and filing requirements will reduce the overall time and expense requirements associated with these activities and reduce the overall number of proceedings which the Company files with the Commission today. This also will result in efficiency gains at the Commission and by other public parties as fewer regulatory filings will have to be processed and resolved. Moreover, UGI Gas plans to submit and seek approval for a unified LTIIP no later than the summer of 2019, and has proposed the adoption of a unified DSIC in this proceeding. Establishing a unified LTIIP and DSIC should enable UGI Gas, as it progresses towards its goal of eliminating non-contemporary materials from its system, to better allocate resources based on assessments of relative risk on a system-wide basis, rather than separate assessments of risk in three service territories.

Q. What impact will the establishment of unified rates have on customer rates?

A. While this topic is addressed in more detail in the direct testimony of Mr. Lahoff (UGI Gas St. No. 8), it is material to note that UGI Gas is not proposing a rate consolidation plan in this case which would require multiple rate cases over multiple years, but is instead proposing to move to uniform consolidated rates in this proceeding. Prompt consolidation is critical to achieving the many benefits of uniform rates, rules and regulations discussed above.

Specifically, in reviewing the impact of unification, the Company applied a "two times" standard under which (1) no rate district would receive more than two times the system average increase, and (2) no rate class within a district would receive more than two times the district average increase (for any rate district with a proposed net increase in total). As further explained in Mr. Lahoff's testimony (UGI Gas St. No. 8, Table 4), the Company's proposal to establish uniform rates and move each rate class an equal percentage towards the system average return is reasonable and appropriate and should be approved. I would also note that a significant portion of the larger increases for some rate classes result from the below system average return of those classes and rate districts at present rates and is not solely due to the establishment of uniform rates.

Table 2 below provides a summary of the bill impact by rate district on UGI Gas's average residential heating customer, average commercial heating customer and average small industrial customer, consistent with customer rate case notices provided by the Company.

Table 2. – Average Monthly Bill Impact

Average Residential Heating Customer Bill Impact			
	Bill Component Impact		
	Total Bill Change	Distribution Rate Change	Purchased Gas Cost Rate Change
South Rate District	16.8%	20.2%	-3.4%
North Rate District	8.5%	5.2%	3.3%
Central Rate District	-8.3%	-11.5%	3.2%

Average Commercial Heating Customer Bill Impact			
	Bill Component Impact		
	Total Bill Change	Distribution Rate Change	Purchased Gas Cost Rate Change
South Rate District	1.5%	5.2%	-3.7%
North Rate District	17.4%	13.1%	4.3%
Central Rate District	10.0%	5.3%	4.7%

Average Industrial Customer Bill Impact			
	Bill Component Impact		
	Total Bill Change	Distribution Rate Change	Purchased Gas Cost Rate Change
South Rate District	-3.3%	0.6%	-3.8%
North Rate District	18.0%	13.3%	4.7%
Central Rate District	8.6%	3.3%	5.3%

Table 2 demonstrates the interplay between uniform base rates and PGC rates. In several instances a decrease in PGC rates will partially offset the impact of higher distribution rates. This will reduce volatility and further supports moving to unified base rates and

PGC rates at the same time. While impacts related to unification differ by rate district and rate class, and some customers will realize increases and other customers will realize decreases, at a system-wide class level, as explained in Mr. Lahoff's testimony (UGI Gas St. No. 8), the Company's proposal to unify all rates and move customer classes an equal percentage towards the system average return is fair and reasonable.

IV. UGI-1 INITIATIVE AND UNITE

Q. Please describe UGI Gas's UGI-1 initiative.

A. UGI-1 is a company-wide improvement initiative focusing on people, tools and processes. UGI Gas's rate districts and predecessor companies have a history of pursuing excellent performance for customers, employees and shareholders. UGI Gas has been building on this past performance to achieve even higher levels of performance by equipping employees for future success and by improving communications throughout the organization. Specifically, UGI Gas has: (a) initiated and advanced the UNITE technology improvement project; (b) migrated all employee computer workstations to a set of common workplace applications; (c) transitioned all field employees to a single set of gas operations and construction processes and specifications; (d) improved building and grounds, including a voluntary initiative to become certified at Company locations under Occupation Safety and Health Administration's ("OSHA") Voluntary Protection Programs ("VPP"); (e) initiated natural gas pipeline facility extension and betterment programs; (f) implemented advanced physical and cyber security measures; (g) implemented a safety improvement program in coordination with DuPont, a globally recognized expert in safety; and (h) enhanced and expanded employee development and training programs.

Q. How do the changes related to UGI-1 benefit customers?

A. UGI-1 has already established and implemented, and will continue to establish and implement, a common set of information systems, tools, equipment, and uniform work management and performance platforms to support UGI's operations. This has allowed, and will continue to allow, UGI Gas to become more efficient and effective in performing all aspects of its business, including handling calls from customers, performing billing and related activities, constructing new distribution facilities, operating and maintaining its gas distribution and transmission systems, and its management of emergencies. An effective and common system of performing and measuring performance will also expedite identification of problems that can be corrected more readily, or even prevented, driving further efficiency gains and service improvements.

The integration of UGI's three separately regulated gas rate districts and one electric distribution company under common systems will help ensure costs incurred to provide service reflect a common way of doing our work, and will help eliminate differences in cost drivers to the extent feasible and where geographic or industry (natural gas versus electric) factors do not dictate a different result.

Q. Please provide some examples of the operational benefits that are being derived from the UGI-1 initiative.

A. UGI Gas's three rate districts have established and implemented a common methodology for rating the severity of natural gas system leaks in line with the Gas Pipeline Technology Committee standard, thereby enabling the allocation of (a) pipeline replacement, (b) leak survey and repair, (c) financial, (d) internal labor, and (e) contractor resources to the segments of its systems that require the most attention based on uniform measures of risk. This common approach to operational management and regulatory compliance has achieved significant improvements to system safety performance in recent years, including reductions in hazardous leaks and leak inventories. As discussed further in the direct testimony of Mr. Bell (UGI Gas St. No. 2), UGI Gas's common set of initiatives in workplace safety and Pennsylvania 1-Call, as well as its Distribution Integrity Management Program ("DIMP") have begun to bear fruit in terms of achieving improved safety based on measurable performance criteria.

Q. Are there examples of additional improved customer service performance?

A. Yes. In the area of natural gas expansion and extension, UGI Gas's customer base has grown by nearly 15%, or by over 84,000 customers, over the past 10 years. This growth rate is well above that of any other natural gas distribution company in Pennsylvania and has been supported by business changes and regulatory initiatives which have facilitated the acquisition and processing of new customers. Examples include: (a) UGI Gas's GET Gas Pilot Program, which has been nationally recognized as an innovative tariff mechanism designed to expand natural gas service to unserved and underserved areas in and around the company's gas distribution service territories; (b) the implementation of joint electric and gas billing; (c) the pilot TED Rider; and (d) the Company's EE&C programs.

Q. What is the UNITE initiative?

A. UNITE stands for "UGI Gas's Next Information Technology Enterprise." Phase I of UNITE replaced and updated UGI's core, non-financial computer systems, and included the replacement of two legacy Customer Information Systems ("CIS") with a new state-of-the-art system shared among the UGI utilities. Having a common CIS has enabled UGI to benefit from a common set of processes and has increased the capabilities for UGI to offer enhanced services, such as online web-based services, which increase the efficiency and availability of rendering service to customers. This new system also supports key Choice business processes. UGI is now moving forward with the UNITE Enterprise Resource Planning ("ERP") project (*i.e.*, "UNITE Phase II"). UNITE Phase II is focused on UGI's financial and supply chain business operations and involves the replacement of UGI's existing Oracle ERP system with SAP's ERP Solution. This system replacement will encompass key business activities such as: Procure to Invoice (Supply Chain Process), Invoice to Pay (Accounts Payable Process), Acquire to Retire (Plant Accounting Process) and Record to Report (General Ledger Process). UNITE Phase II also includes a concurrent project by implementing SAP's Fieldglass solutions, which will improve UGI's contractor billing process. The initial go-live for UNITE Phase II is targeted for April 2019. These and future UNITE initiatives either have or will: reduce operational risks related to maintaining outdated legacy applications; improve operational capabilities with new "scalable" technology platforms; standardize and reduce the number of duplicate systems and processes across UGI; improve business information and decision making; and increase efficiency.

V. INTERRUPTIBLE REVENUES

Q. Is UGI Gas proposing to continue to offer non-core market customers the option of receiving interruptible service?

A. Yes. Unlike some other utility services, natural gas is subject to competition from alternative fuels, direct customer bypass and locational competition, and there are no uses for natural gas for which there are no other viable energy alternatives. Competition from alternative energy sources is particularly acute for the company's largest customers, and for those with installed alternate fuel capabilities. For this competitive market, the Company has traditionally pursued and maintained negotiated rates that provide the Company with the ability to attract and retain interruptible service throughput on its system, as doing so maximizes overall system utilization efficiency and provides for service revenues which serve to otherwise either lower rates for all other customers and/or delay the need for rate relief. Today, UGI Gas's three rate districts currently provide interruptible gas service to 380 customers under negotiated contracts that have rates based on the available alternatives.

Since the revenues derived from opportunistically providing interruptible service when market opportunities present themselves are difficult to guarantee, UGI Gas generally does not make distribution system investments to serve such interruptible loads given the threat that such investments could be stranded under changing market conditions. Relatedly, UGI Gas has traditionally been afforded the tariff rate flexibility to discount interruptible service rates below the levels established for firm service rates to compete with each interruptible service customer's energy or locational alternatives, a process referred to as value-of-service pricing.

In setting rates, UGI Gas has traditionally agreed to revenue allocations which provide for an effective fixed interruptible revenue credit to those revenue requirements otherwise applicable to firm customers. Between rate cases, the Company has born the risk related to these revenue allocations and worked to manage that risk through careful attention to the management of value of service pricing in order to maximize interruptible revenues. This rate structure has historically benefitted UGI Gas customers both through the fixed interruptible revenue credit established in base rate cases and, when UGI Gas has been able to achieve interruptible revenues in excess of the credit, through the decreased need for UGI Gas to seek base rate relief. Indeed, this rate design was a significant factor in enabling what is now the UGI South Rate District to avoid a base rate filing for over twenty years before its most recent base rate case.

Q. Please describe the Company's proposal related to establishing an EEF.

A. UGI Gas proposes to establish an EEF to support the continued extension and expansion of natural gas into unserved and underserved areas in and near its service territory. The EEF will be funded with 20% of FPFTY interruptible revenues per year, or at an initial level of $4.9 million per year. Amounts from this EEF will then be utilized to reduce the otherwise applicable GET Gas surcharge paid by participating customers. As further described in the testimony of Mr. Lahoff (UGI Gas St. No. 8), the applicable GET Gas surcharge for residential customers will be $21.75 per month. This updated charge represents the net amount of the updated recalculation of the GET Gas surcharge consistent with the Company's latest cost data projections and the reduction of the surcharge amount via application of EEFs to achieve the targeted $21.75 per month. This uniform, reduced charge is expected to improve GET Gas participation rates, as further described in the testimony of Mr. Hart (UGI Gas St. No. 9). The EEF would continue to fund any difference between $21.75 per month and the otherwise calculated GET Gas surcharge amount for a period of up to 10 years, or the duration of the payment obligation to the participating GET Gas residential customer. In a similar manner, the GET Gas surcharge applicable to commercial customers will be fixed at a target level of $7.86 per month with an additional $1.07 per Mcf surcharge.

Additionally, the Company is proposing to utilize the EEF as funding for certain "last mile" extension and expansion projects. Specifically, where an extension or expansion project is awarded a grant in accordance with the Commonwealth of Pennsylvania's Pipeline Investment Program ("PIPE") program, the Company will match the PIPE grant amount up to 100% with funds from the EFF, as may be required in order to meet tariff line extension criteria. As noted on the PIPE website:

> *The Pipeline Investment Program (PIPE) provides grants to construct the last few miles of natural gas distribution lines to business parks, existing manufacturing and industrial enterprises, which will result in the creation of new economic base jobs in the Commonwealth while providing access to natural gas for residents.*

Establishing the EEF will bring numerous direct and indirect benefits related to energy cost savings, economic development, lowering overall environmentally harmful emissions, greater energy utilization efficiencies and the continued development and utilization of Pennsylvania's natural gas resources.

Q. Please describe the Company's proposal related to creating an incentive sharing mechanism.

A. As part of its overall proposal, UGI Gas proposes to create an incentive sharing mechanism for interruptible revenues which allows the Company to retain 20% of FPFTY interruptible revenues, or $4.9 million annually. This incentive sharing mechanism is patterned, in part, off the existing and long-standing incentive sharing mechanism which was established in PGC proceedings related to sharing the profits related to Off-System Sales. Specifically, the Company is permitted to retain 25% of net profits related to Off-System Sales in order to maximize Off-System Sales which, in turn, otherwise reduce gas costs for UGI Gas's PGC and Choice market customers. The Company believes incentive sharing should also apply to interruptible revenues, which are a direct result of individually negotiated value of service rates with interruptible customers. As with the incentive created for the Company to maximize Off-System Sales margins, a sharing mechanism allowing for the Company to retain 20% of interruptible revenues will incent the Company to maximize interruptible revenues. To the extent the Company performs in this role, all customers stand to benefit by the creation of a substantial, sustainable revenue amount that provides an offset to the revenue requirement established for other classes in future rate case proceedings and also maximize the benefits that interruptible revenues can provide to otherwise delay the need for rate relief.

This value-of-service basis requires considerable effort on the Company's part to evaluate market conditions in order to correctly identify each prospective customer's options and enter into what are often difficult negotiations to establish an appropriate value of service rate. As such, incenting those efforts is appropriate, in my view. Thus, the Company is proposing to establish an incentive sharing mechanism where 20% of interruptible revenues are retained by the company, with such amount being treated "below the line" for ratemaking purposes in this proceeding.

Q. Please describe the impact that the above proposals related to the use of interruptible revenues have on the Company's cost of service study presented in this proceeding.

A. In the cost of service study submitted in this proceeding, Mr. Herbert (UGI Gas St. No. 6) is reflecting 60% of total FPFTY interruptible revenues to reflect the 20% to be utilized for the EEF and the 20% to be utilized in the incentive sharing mechanism. This amount of interruptible revenue helps mitigate the impact of the rate increase on other classes, based on the interruptible class's 1.66 relative rate of return shown in UGI Gas Exhibit D.

VI. MANAGEMENT EFFECTIVENESS AND PERFORMANCE

Q. What actions have UGI Gas taken that reflect superior management performance?

A. UGI Gas has focused on a number of areas to enhance and improve the quality and effectiveness of its management performance. These management efforts include:

- An accelerated infrastructure replacement plan focused on replacing all remaining cast-iron and bare steel mains, as further explained in the testimony of Hans G. Bell (UGI Gas St. No. 2). UGI Gas already is a leader in the Commonwealth, as its distribution system has the highest percentage of contemporary mains. Moreover, as shown in UGI Gas's LTIIPs filed in accordance with Act 11, the Company projects that it will eliminate all cast-iron mains by February 2027 and all bare steel mains by September 2041. The Commission approved the Company's initial LTIIP filing on July 31, 2014, at Docket No. P-2013-2397056, and its modified LTIIP on June 30, 2016 at the same docket.
- Since early 2017, UGI Gas has been developing plans to construct a new state-of-the-art centralized training center.

- Developing and implementing an innovative expansion and extension program (*i.e.*, GET Gas). The pilot GET Gas program has been highlighted nationwide at American Gas Association events and has been called a model program.
- Developing and implementing the TED Rider to facilitate cost-effective expansions of its natural gas service to smaller Commercial and Industrial customers, as further described in the direct testimony of Shaun M. Hart (UGI Gas St. No. 10).
- Managing growth with an increase in overall customer counts of nearly 15% since 2008. All else being equal, this growth has helped reduce the need for base rate increases.
- Finishing in first or second place in the J.D. Power award for customer satisfaction among utilities in each of the last six years, and winning the J.D. Power #1 in Customer Satisfaction award a total of seven times (2003, 2004, 2005, 2006, 2007, 2013 and 2014) since UGI was first included in the survey in 2003 by J.D. Power.
- Developing and implementing numerous safety improvement initiatives to reduce injuries and motor vehicle accidents, as further explained in the testimony of Hans G. Bell (UGI Gas St. No. 2). These initiatives include pursuing OSHA verification of a VPP, a First Move Forward policy, a "Making a Difference" safety program, use of dash-cams to record and review incidents or close-calls, Smith Driving School training, establishing safety committees for root cause analysis and review, a Company-wide education and appropriate employee coaching and engagement tracks, and UGI's newest initiative working in

conjunction with the globally recognized DuPont safety group focused on the core issue of safety culture across the Company.

- Focusing on increasing spend with Minority, Women and Disabled Owned Businesses ("Diversity Spend"). Internal initiatives to increase focus on Diversity Spend now include a requirement for each member of the Purchasing Department to complete 10 Continuing Education Hours of ISM Diversity Training and a requirement that UGI Gas's Purchasing Supervisor must be a Certified Professional in Supplier Diversity (C.P.S.D.). Total Diversity Spend by the Company has increased in the past two years by over 17% annually and over 10% annually for 2017 and 2018, respectively, and represents over $42 million of expenditures annually.
- Launching a Company-wide initiative, UGI-1, which is aligning UGI Gas's people, processes and tools to drive additional efficiencies and effectiveness across the organization, including the implementation of new state-of-the-art customer information, work management and other supportive systems.
- Undertaking the UNITE Project to further improve customer service and other functions. As previously discussed, the UNITE Project is an information system modernization project. Phase I of the Project entailed the development and implementation of a new CIS to replace our two legacy mainframe CIS systems. This new CIS harmonized the two systems and provides increased functionality and improved customer service. Phase II related to ERP replacement is currently underway and will, in particular, modernize key financial and business management systems.

- Implementing an EE&C Plan. The EE&C Plan currently is a comprehensive portfolio of energy efficiency and conservation programs that was designed to assist customers save energy through various cost-effective measures and, in this case, the Company proposes to expand the program, with some modifications, to customers located throughout the service territory rather than just the North and South rate districts. The full contents of the EE&C Plan and its substantial environmental benefits are described in detail in the direct testimony of Theodore M. Love (UGI Gas St. No. 13).
- Fostering clean fuel adoption. UGI Gas will have over 100 compressed natural gas fueled vehicles ("NGVs") as part of its fleet by October 2019. These vehicles provide significant reductions in carbon emissions and serve to demonstrate the benefits existing today for NGVs to both produce favorable operating costs as well as improve the environment.

The above-described initiatives, as well as those described by the other witnesses, demonstrate UGI Gas's commitment to and focus on providing and improving safe and reliable distribution services to its customers.

UGI Gas believes that the management efforts described above and the other improvements described by the UGI Gas witnesses in this proceeding, as well as the company's provision of safe and reliable service at reasonable rates, support an additional upward adjustment of 0.25% to the Company's equity return in recognition of its management effectiveness, which is included in the 11.25% equity return requested in this proceeding.

Q. Does UGI Gas play a constructive role in the communities it serves?

A. Yes. For example:

- Each year UGI invests more than $1.0 million to support education improvement programs across the Company service territory. UGI Gas also supports: childhood literacy; enhanced "STEM" (science, technology, engineering and math) curriculum in elementary schools; funding for technical training programs for high school students; and programs that provide support and mentoring for women and minority engineering school students.
- UGI Gas employees also commit significant personal time and resources to support community initiatives. For example, 709 UGI Gas employees donated more than 60,000 hours to assist their communities in 2017. UGI Gas employees also donated personal funds to better their communities, including over $350,000 contributed by UGI Gas employees as part of the Company's 2018 United Way campaign. Combined with corporate contributions and retiree contributions, total support provided to United Way agencies serving communities in the UGI Gas service territory in 2018 totaled nearly $700,000.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT PJS-1

PAUL J. SZYKMAN

CHIEF REGULATORY OFFICER

May 2017 – Present	Chief Regulatory Officer UGI Utilities, Inc., Reading, PA
2015 – April 2017	Vice President – Rates & Government Relations Vice President & General Manager – Electric Utilities UGI Utilities, Inc., Reading, PA
2014 – 2015	Vice President – Rates & Government Relations UGI Utilities, Inc., Reading, PA
2008 – 2014	Vice President – Rates UGI Utilities, Inc., Reading, PA
2003 – 2008	Director, Rates & Gas Supply UGI Utilities, Inc., Reading, PA
2001 – 2003	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1999 – 2001	Manager, Federal Regulatory Affairs & Contract Admin. UGI Utilities, Inc., Reading, PA
1999 – 1999	Principal AMS, Fairfax, VA
1996 – 1999	Manager, Rates & Strategic Planning UGI Utilities, Inc., Reading, PA
1994 – 1996	Supervisor, Transportation UGI Utilities, Inc., Reading, PA
1991 – 1994	Rate Designer UGI Utilities, Inc., Reading, PA
1989 – 1991	Market Research Analyst UGI Utilities, Inc., Reading, PA
1986 – 1989	Industrial / Commercial Representative UGI Utilities, Inc., Reading, PA
1981 – 1985	Penn State University B.S. Mechanical Engineering

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

R-00932927	UGI Utilities, Inc. – Gas Division; Restructuring (Supplement 91)
R-00016376	UGI Utilities, Inc. – Gas Division; Stroehmann Bakeries
P-00032043	UGI Utilities, Inc. – Gas Division; Granger Energy
P-00032054	UGI Utilities, Inc. – Gas Division; Modification of Security Requirements
R-00049422	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00050539	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00061502	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-00072334	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-00072335	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2008-2039284	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-2008-2039417	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2008-2079675	UGI Central Penn Gas; Base Rate Case
R-2008-2079660	UGI Penn Natural Gas; Base Rate Case
R-2009-2105911	UGI Utilities, Inc. – Gas Division; Purchased Gas Cost 1307(f)
R-2009-2105904	UGI Penn Natural Gas; Purchased Gas Cost 1307(f)
R-2009-2105909	UGI Central Penn Gas; Purchased Gas Cost 1307(f)
R-2010-2214415	UGI Central Penn Gas; Base Rate Case
R-2015-2518438	UGI Utilities, Inc. – Gas Division; Base Rate Case
R-2016-2580030	UGI Penn Natural Gas; Base Rate Case
R-2017-2640058	UGI Utilities, Inc. – Electric Division; Base Rate Case

UGI GAS STATEMENT NO. 2 – HANS G. BELL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 2

Direct Testimony of
Hans G. Bell

Topics Addressed: **System Operations**
Capital Planning
System Reliability and Safety
New Safety Initiatives
Environmental Program and Remediation Costs

Dated January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Hans G. Bell. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. Please describe your educational background and work experience.

A. They are set forth in my resume attached as UGI Gas Exhibit HGB-1 to my testimony.

Q. What are your responsibilities as COO?

A. As COO, I am UGI's senior executive accountable for providing technical leadership and strategic direction to all gas and electric engineering and operations functions. I am therefore responsible for long-term strategic infrastructure investment plans, annual capital budgets, engineering and operations support, operations, facilities management and energy supply and planning. Under my direction are the Vice President of Engineering and Operations Support, the Vice President of Operations, the Director of Security & Facilities, the Director of Electric Engineering and Operations, the Director of Energy Supply and Planning, and the Director of Business Support Services.

Q. Have you presented testimony in proceedings before a regulatory agency?

A. Yes, between 2013 and 2016, I testified in proceedings involving the Distribution System Improvement Charge ("DSIC") for UGI Gas and its former subsidiaries UGI Central Penn Gas, Inc. ("UGI CPG") and UGI Penn Natural Gas, Inc. ("UGI PNG"). I also testified in the base rate proceedings of UGI Gas in 2016 and UGI PNG in 2017. Please see UGI Gas Exhibit No. HGB-1 for a complete listing of the proceedings in which I have testified and their docket numbers.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. In my testimony, I will address the following topics: (1) natural gas system operations; (2) capital planning; (3) system reliability and safety; (4) new safety initiatives; and (5) the environmental program and remediation expenses.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following UGI Gas Exhibits HGB-1 through HGB-5. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. NATURAL GAS SYSTEM OPERATIONS

Q. Please provide an overview of UGI Gas's operations.

A. UGI Gas provides natural gas service to approximately 642,000 customers in Pennsylvania through a system consisting of approximately 12,000 miles of gas distribution mains and 300 miles of natural gas transmission mains as of December 31, 2017.[1] UGI Gas currently provides natural gas service in the North, South, and Central rate districts pursuant to three separate tariffs. The North Rate District is largely made up of rural communities, with Wilkes-Barre, Scranton, and Williamsport and the surrounding communities constituting the primary urban areas within the service territory. The South Rate District is split into two non-contiguous regions: a primary and secondary region. The primary region spans twelve counties: Franklin, Cumberland, York, Dauphin, Lebanon, Lancaster, Berks, Chester, Montgomery, Lehigh, Bucks, and Northampton. It also includes five of Pennsylvania's ten largest cities: Allentown, Bethlehem, Harrisburg, Lancaster and Reading, along with the suburban communities surrounding them. The secondary region spans four counties: Schuylkill, Luzerne, Carbon, and Monroe and is largely made up of rural communities, with Hazleton being the largest city in that area. The Central Rate District has a largely rural, non-contiguous service territory that encompasses all or parts of 37 counties in northeastern, central, and northwestern Pennsylvania.

Q. How many operations centers and support facilities does UGI Gas have?

A. UGI Gas has a total of thirty five (35) operations centers and support facilities split between the North, South, and Central rate districts. Several of the operations centers, such as Lehigh, Harrisburg, Middletown, Lewistown, Port Allegany, and Wilkes-Barre, also act as regional training facilities. There is also a stand-alone training facility in Reading.

[1] Per 2017 U.S. Department of Transportation Report reflecting mileage on December 31, 2017.

Q. How does UGI Gas staff its operations?

A. As of September 30, 2018, UGI had a total of 1,670 full-time employees. Various management and support services are provided by UGI's employees to the Electric Division and the Gas Division (*e.g.*, finance and accounting, payroll, supply, rates, purchasing, fleet, marketing, administrative duties, customer service, credit and collection, and information technology). Operations and Engineering staff are largely assigned to either the Gas Division or Electric Division. UGI also benefits from management and support services provided by its parent company UGI Corporation (*e.g.*, insurance, legal, treasury operations, and corporate governance).

III. <u>CAPITAL PLANNING</u>

Q. Please describe the categories of projects included in the capital budget for UGI Gas.

A. The main areas for which UGI Gas develops capital budgets are: (1) replacement and betterment infrastructure; (2) new business; (3) facilities; (4) information technology; and (5) supply. The budgeting process is further described in the direct testimony of Stephen F. Anzaldo (UGI Gas St. No. 3).

Q. How are projects chosen for inclusion in UGI Gas's capital budget?

A. Replacement and betterment infrastructure projects are chosen for inclusion in the capital budget using a risk-based prioritization process. New business projects are chosen based on forecasts of new business, customer conversions, customer counts, and construction and development. Facilities projects are a prioritized set of building-related projects. Information Technology ("IT") projects are selected based on need for new systems and hardware, and replacement of old systems and hardware. Supply projects are selected based on their ability to maximize the utilization of upstream interstate supply capacity and react to cost of supply (*e.g.*, our attempt to optimize low-cost Marcellus supply). Capital projects are budgeted on a project level and rolled up to the Electric and Gas Divisions, however, capital projects of general application to UGI are budgeted by UGI and costs are allocated to the divisions and rate districts in accordance with the Modified Wisconsin Formula ("MWF").

Q. Please describe the risk-based prioritization process used to evaluate replacement and betterment infrastructure projects.

A. UGI Gas's risk-based prioritization process prioritizes the replacement of cast iron and bare steel pipe, which are more susceptible to failure from corrosion, cracks and leakage than other pipe materials. Where other facilities located near selected projects are determined to be prone to failure, they will also be prioritized for replacement. As part of its infrastructure upgrade, UGI Gas replaces associated distribution equipment and installs additional safety and monitoring equipment that is compatible with the upgraded design. UGI Gas installs excess flow valves, replaces and potentially relocates meters, and replaces risers, meter bars, regulator stations and service regulators. UGI Gas's prioritization of projects for its capital budgets is consistent with the Long Term Infrastructure Improvement Plan ("LTIIP") for each of its rate districts, which were approved by the Commission at Docket Nos. P-2013-2397056 (North Rate District), P-2013-2398833 (South Rate District) and P-2013-2398835 (Central Rate District) (Order entered June 30, 2016). These LTIIPs were extended until December 31, 2019 by

Commission Order entered August 2, 2019. LTIIP replacement investments are in turn identified and prioritized on a risk basis in accordance with UGI Gas's Distribution Integrity Management Plan ("DIMP").

Q. How does UGI Gas's actual capital spending compare to budgeted capital spending?

A. With respect to replacement and betterment spending, UGI Gas's historical spending is closely aligned with budgeted capital, as shown on UGI Gas Exhibit HGB-2.

Q. How do budgeted capital expenditures compare to the Company's claim in this proceeding?

A. UGI Gas's budgeted capital expenditures for the Future Test Year ending September 30, 2019 ("FTY") and the Fully Projected Future Test Year ending September 30, 2020 ("FPFTY"), and adjustments to capital budget are set forth on UGI Gas Exhibit HGB-3. There are some differences in budgeted and forecast FTY and FPFTY capital expenditures due to adjustments made after development of the budget. Budgeted capital expenditures for the FTY were $354.2 million while the adjusted capital expenditures are $351.6 million. Budgeted capital expenditures for the FPFTY were $366.2 million while the adjusted capital expenditures are $361.9 million. The specific adjustments are set forth in UGI Gas Exhibit HGB-3 under the subtotal for budgeted Non-DSIC Expenditures. They include adjustments for Project Connect, UNITE Phase 3, the Energy Management Website, the expansion of Daily Metering, and the Training Center.

Q. Please explain the capital budget adjustment for Project Connect.

A. This is a $4.9 million increase to the FTY capital budget to reflect the allocation of costs from UGI Corporation to UGI Gas to support a Human Resource Information System ("HRIS"). The costs associated with the HRIS project, also referred to as Project Connect, pertain to the ongoing implementation of SuccessFactors, a comprehensive human resources cloud-based solution that includes modules for recruiting, onboarding, management of personnel files, learning management, payroll and time and attendance, as well as benefits.

Q. Please explain the capital budget adjustment for UNITE Phase 3.

A. As originally budgeted, UNITE Phase 3 anticipated having a work and asset management solution implemented during the FPFTY. As the project developed it was determined that this component of UNITE will be placed into service after the FPFTY and therefore the costs attributed to those components were deducted from the FTY and FPFTY budgets in the amount of $7.5 million and $22.5 million, respectively.

Q. Please explain the capital budget adjustment for the Energy Management Website.

A. The $480,000 FPFTY budget increase for the Energy Management Website is due to modifications to the Company's GIS website in order to support transportation program rule changes. The transportation rule changes and the planned upgrade of the Energy Management Website are discussed in more detail in the direct testimony of Angelina Borelli (UGI Gas St. No. 12).

Q. Please explain the capital budget adjustment for the expansion of Daily Meters.

A. The $2.7 million increase to the FPFTY budget is due to the Company's proposal to expand daily metering to all non-choice transportation customers in the Company's service territory. The daily metering expansion proposal is discussed in further detail in the direct testimony of Shaun M. Hart (UGI Gas St. No. 9).

Q. Please explain the capital budget adjustment for the expansion of the Training Center.

A. The Company had budgeted $18 million for the Training Center with $5 million in the FTY budget and $13 million in the FPFTY budget, which is described in further detail in Section V of my direct testimony. The $15 million increase in the Training Center for FPFTY is due to the additional amounts needed for site preparation and construction of the center.

IV. SYSTEM RELIABILITY AND SAFETY

Q. Please describe the physical composition of UGI Gas's distribution system.

A. Due to its long-term operation, the UGI Gas distribution system is comprised of pipeline facilities composed of a mixture of materials indicative of the industry's technological advancement over time. Cast iron mains can be found in the oldest parts of the system. The industry then transitioned to bare steel and wrought iron piping, which were prevalent until the 1960s. The first generation of plastic piping was introduced in the early 1970s. Materials installed since the 1970s include polyethylene (PE) and coated steel piping. Overall, the UGI Gas system is composed of approximately 87%

contemporary materials, which UGI Gas defines as cathodically-protected steel and plastic.

Q. Please discuss UGI Gas's main replacement program.

A. UGI Gas's main replacement program constitutes a large part of its capital budget. UGI Gas has been identifying and repairing, improving, or replacing its distribution infrastructure on an accelerated basis. As I stated above, UGI Gas has a Commission-approved LTIIP. The LTIIP commits UGI Gas to the replacement of all of its cast iron pipelines by February 2027, and all of its bare steel and wrought iron pipelines by September 2041. UGI Gas is also committed to replacing gas service lines and moving inside regulators and, where applicable, inside meters to outside locations on a planned basis in conjunction with the replacement of the mains to which they are connected. These projects meet the requirements for recovery in a DSIC and are therefore "DSIC-eligible." As of December 31, 2017, the remaining mileage of UGI Gas cast iron and bare steel/wrought iron for each of its rate districts is set forth in Table 1 below:

Table 1. Remaining Cast Iron and Bare Steel Mileage as of December 31, 2017[1]

Rate District	Cast Iron	Bare Steel
North	23	123
South	213	300
Central	1	590
Total	237	1013

[1] 2018 Calendar year figures will be available March 15, 2019, in UGI Gas's annual distribution report.

Q. Does UGI Gas track capital investment associated with these DSIC-eligible main replacements?

A. Yes. UGI Gas tracks DSIC-eligible capital placed in service monthly on a calendar year basis and reports that information to the Commission in its Annual Asset Optimization Plan ("AAOP") on a per rate district basis.

Q. Has UGI Gas met its DSIC-eligible main replacement goals set by its LTIIP?

A. Yes. As described in UGI Gas's LTIIP, the UGI Gas rate districts have a combined total annual goal of 64 miles of cast iron and bare steel replacement. From 2014 through 2018 the Company has exceeded its five-year aggregate replacement goals by replacing 323.4 miles of main versus the 316 miles projected. Table 2 below shows the forecasted and actual replacement figures for UGI Gas for the first five years of the LTIIP.

Table 2. Forecasted versus actual Main Replacement

	2014 (in miles)	2015 (in miles)	2016 (in miles)	2017 (in miles)	Projected 2018 (in miles)[1]	Total
UGI Gas Forecast	62	62	64	64	64	316
UGI Gas Actual	62.6	67.4	67.3	65.1	62.4	324.8

[1] Calendar year 2018 data will be available in March of 2019.

Q. How has UGI Gas's actual DSIC-eligible capital investment trended over the past five years?

A. UGI Gas's capital investment has, in general, exceeded its forecasts, which necessitated UGI Gas to file amended LTIIPs in 2016 that are applicable to all three rate districts. Table 3 shows the actual DSIC-eligible capital-spend from 2014 through 2017.

Table 3. DSIC-eligible capital spend

Rate District	2014 ($ millions)	2015 ($ millions)	2016 ($ millions)	2017 ($ millions)	Forecasted 2018[1] ($millions)
North	$20.3	$26.7	$32.8	$37.6	$45.3
South	$52.1	$61.6	$72.0	$95.7	$101.2
Central	$5.6	$17.9	$25.4	$18.8	$23.6
Total	**$78**	**$106.2**	**$130.2**	**$152.1**	**$170.1**

1. Calendar year 2018 actual results will be included as part of the Annual Asset Optimization Plan filing in March of 2019.

Q. Does UGI Gas have a projection of its DSIC-eligible capital spend for FTY and the FPFTY?

A. Yes. As I stated earlier in my testimony, and as shown on UGI Gas Exhibit HGB-3, fiscal year 2019 capital spending is forecast at $351.2 million, with $194 million of that projected capital spending being DSIC-eligible, through the end of the FTY when new rates established in this case are expected to take effect. The fiscal year 2020 capital spending is forecast at $361.9 million, of which $210.4 million meets the definition of DSIC-eligible capital in our current LTIIPs.

Q. What are the Company's plans with respect to a new LTIIP?

A. The current LTIIP is set to expire at the end of 2019. The Company plans to file a new LTIIP for each of the rate districts in the spring of 2019. The filing will be made on a consolidated basis with the three rate districts shown on a separate and rolled-up basis. Therefore, while capital spend and mileage targets will be set out separately by rate district, assuming Commission approval of the Company's proposal to merge distribution rates in this proceeding, these budgets and mileage targets would be merged into one target for the entire UGI Gas Division.

Q. Is there an advantage to having one LTIIP for UGI Gas rather than three separate LTIIPs?

A. Yes. Even prior to the merger, UGI focused on combined mileage and spending targets and prioritized risk by taking a holistic look at the combined system rather than its individual subsidiaries, so I do not want to overemphasize the impact that a combined LTIIP will have on our prioritization of projects. However, in the current LTIIPs, there are still individual company mileage and spending targets that are factors in the planning of replacement projects. By having one budget and one mileage target applicable to the entire Company, we will have more flexibility in prioritizing replacement projects and will not be required to select replacement projects in order to meet certain mileage and spending targets by rate district.

Q. How does UGI Gas classify leaks?

A. UGI Gas classifies underground leaks as "A", "B", and "C", with "C" being the most severe. An "A" leak is an underground leak that is non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous. "B" leaks are underground leaks that are recognized as being non-hazardous at the time of detection, but justify a scheduled repair based on a probable hazard. "C" leaks are underground leaks that represent an existing or probable hazard to persons or property, and require immediate repair or continuous action until the conditions are no longer hazardous.

Q. Please discuss UGI Gas's efforts to reduce system leaks.

A. As a part of its DIMP, UGI Gas regularly re-assesses all system risks and leakage trends to determine if additional or accelerated actions are required to further reduce system leaks. For example, as shown on UGI Gas Exhibit HGB-4, since 2015, the Company has decreased its inventory of B leaks by 46%.

Q. How is UGI Gas's performance in the area of emergency response rate?

A. UGI Gas performs very well in the timeliness of emergency response to gas odor complaints. For the year ended September 30, 2018, 97.7% of the time a first responder arrived on premise within 45 minutes of receipt of an odor call. UGI Gas's performance is better than industry averages and is attributable to factors such as staffing levels and after-hours coverage. It also should be noted that UGI Gas sets performance goals on a 45-minute response, whereas most other distribution companies' goals are based on a one hour response target.

Q. What programs does UGI Gas have in place regarding employee, customer, and system safety?

A. Safety performance is now and will always remain a fundamental imperative at UGI. UGI has several continuing safety initiatives in place to further develop its safety culture and drive sustainable improvements in safety performance. One such program is the UGI Making a Difference Safety Incentive Program, which rewards employees for supporting safety culture through actions such as demonstrating positive safety behaviors, leading safety meetings, reporting safety issues, or participating in safety education.

The Company is also in its third year of working on compliance with the Voluntary Protection Plan ("VPP") program of the United States Occupational Health and Safety Administration ("OSHA"). The Company is ahead of its forecasted VPP progress. In fiscal year 2018, ten facilities were made ready for OSHA VPP inspection (above the eight facility goal) and 37 locations have completed their monthly inspections (above the 35 facility target).

Other ongoing safety programs and tools include Smith driver training; the 24 hour Triage Nurse Hotline; the Fleetmatics dispatching tool and incentive program; and DriveCAM selective driver monitoring.

V. NEW SAFETY INITIATIVES

Q. Has the Company recently launched any new safety initiatives?

A. Yes. The Company is developing a centralized training facility and has initiated a Safety Culture Transformation Program.

Q. Please explain the Company's project to create a centralized training facility.

A. Since early 2017, UGI Gas has been planning to build a centralized training facility. The training facility is scheduled to be in service during the FPFTY. The state-of-the art training facility will include an approximately 60,000 square foot training center, a "safety town" for real-life outdoor training inclusive of leak pinpointing and investigation, and a separate welding and tapping center. The interior of the training center will include offices, meeting rooms, a safety lab, several lecture rooms, a service lab, a metering and regulation lab, and a computer lab. Classrooms and laboratories are designed for four primary training deliverables: (1) safety; (2) construction and maintenance; (3) measurement and regulation; and (4) utility service.

A property has been identified in Berks County as the site for the training center. A Letter of Intent ("LOI") was executed in December of 2018. The Company is now engaged in due diligence on the property, which will include Phase I and Phase II environmental site assessments.

Q. What is the anticipated cost of the Training Center?

A. The anticipated capital cost of this project is $34 million, which includes the cost for land acquisition, site improvements, and construction. The land acquisition costs are based on the LOI purchase price as well as the anticipated purchase of an adjacent parcel. The cost of site improvements and construction are based on facility construction bids the Company received from four construction companies in response to the Company's request for proposal, which in turn was based on detailed scaled architectural drawings of the proposed training center.

Q. What process did the Company go through to evaluate the location and design of this new training facility?

A. As mentioned above, the Company has been investigating the development of a centralized training center since early 2017. Company representatives have visited and reported back on the training facilities of other regulated utility companies, such as Atmos Energy, Dominion East Ohio ("Dominion"), Columbia Gas of Pennsylvania ("Columbia"), and Washington Gas Light. Company representatives conducted visits of the Dominion and Columbia facilities accompanied by the architect that the Company engaged for its training center, so that the architect would benefit from seeing the existing training centers in operation. In addition to conducting site visits, the Company received and reviewed detailed plans of certain of these facilities. The determination of our functional needs for this training facility were based on these site visits, plan reviews, and discussions with colleagues within and outside the utility industry, as well as internal discussions within UGI Gas. Due to the competitive commercial real estate market that Pennsylvania is now experiencing, it took some time to locate property sited centrally within our service territory. We were fortunate to locate the Berks County property for which we have executed the LOI, as that location is conveniently located near some of the major routes traversing our service territory.

Q. Why does the Company believe that a centralized center is needed?

A. As I mentioned earlier, the Company does have regional training centers. These centers grew organically over time as a result of the Company's acquisition of smaller utilities and then, more recently, mid-sized gas utilities. The Company's existing training centers are appropriate for routine training and provide opportunities for employees to do web-based and computerized training, as well as table top exercises and they will continue to serve UGI in that capacity. However, consistent with our goal for enhancing our safety performance, more sophisticated state-of-the-art training facilities are needed (*e.g.* a robust leak simulation field). This will enable more access to live gas training and real-world equipment to improve employee performance and confidence when they start working in the field. The planned training facility will provide those opportunities.

A large, centralized training center also will permit a large cross section of UGI Gas employees to train together. Our current training facilities lack sufficient capacity to train large groups of employees. Because the Company is a product of mergers and acquisitions, it is especially important to train employees from different regions together to reinforce a consistent culture and promote standardized materials and practices. The Company has sized the proposed training facility to permit large-scale training.

Lastly, we expect to make the facility available for emergency responder training as a means of improving coordination between the Company and emergency response agencies.

Q. Please describe the Safety Culture Transformation Program ("SCTP").

A. In 2018, UGI launched an initiative to transform its safety culture in partnership with DuPont Sustainable Solutions ("DSS"). The first stage of this project was a safety culture assessment, which began in July of 2018, to develop a safety culture baseline. This initial assessment included documentation review, focus group interviews at ten field operating centers, and Company-wide administration of the DuPont Safety Perception Survey™. DSS reviewed with Company personnel the Company's current safety programs, and separate workshops were held with UGI leadership and key safety personnel to train on the techniques and strategies for developing affective safety messaging and training.

Based on the initial assessment, the Company and DSS embarked upon the SCTP, which officially launched the week of December 3, 2018, with ten Company-wide presentations to introduce the program and the release of the Company's new internal safety vision statement "I'll be there." The SCTP is projected to be an ongoing endeavor. The Company has executed a Scope of Work for Phase I of the initiative, with costs projected through 2021. The first phase of the Program, which will span 2019 and 2020, will consist of three work streams: (1) Governance - Operational Rigor and Managing Process; (2) Expanding Safety Leadership Capabilities; and (3) Branding and Communication to Advance the Culture. The culmination of this initial phase will produce a functional safety framework that will manage all of the Company's other safety programs, as well as non-programmatic areas such as: (1) Safety Leadership Training; (2) Communication and Branding; (3) Operational Staffing and Evaluation; (4) Safety Rules and Procedures; and (5) Technical Training.

As indicated on UGI Gas Exhibit HGB-5, the cost for the SCTP in the FPFTY is anticipated to be $1.04 million. Of this total, $133,046 for personnel costs was included in the FPFTY budget. The remaining programmatic costs were not available to the Company when the budget was prepared. Of these programmatic costs, $819,476 has been allocated to UGI Gas in accordance with the MWF. The Company has therefore adjusted its operating expense by $819,476 as referenced in the testimony of Mr. Anzaldo (UGI Gas St. No. 3).

VI. ENVIRONMENTAL

Q. Please discuss environmental management at UGI Gas.

A. The environmental group at UGI Gas is focused on both environmental compliance and permitting for current operations and addressing historical environmental liabilities. The Company's environmental activities are comprised of three groups: (1) the investigation and remediation of environmental impacts related to historical operations; (2)

environmental compliance activities, such as permitting and operational improvements; and (3) sustainability and methane reduction activities.

Q. Please describe the Company's investigation and remediation of environmental impacts related to historical operations.

A. From the late 1800s through the mid-1900s, UGI and its predecessors owned and operated a number of manufactured gas plants ("MGPs") that, prior to the general availability of natural gas, generated gas from other fuel stocks for residential, commercial and industrial customer use. In Pennsylvania this process generally used coal as a fuel stock. Some constituents of coal tars and other residues of the manufactured gas process are today considered hazardous substances under state and federal environmental laws. Since October 1, 2018, UGI is operating its environmental remediation program under the auspices of three consent orders and agreements ("COA") with the Pennsylvania Department of Environmental Protection ("PADEP") – one per rate district – to address the remediation of specified former MGP sites. The UGI North and UGI Central COAs will terminate on December 31, 2020. The UGI South COA will terminate on October 1, 2031. The Company and PADEP have discussed their mutual intention to enter into one consolidated COA with a consolidated budget after the conclusion of this proceeding with that Consolidated COA having a termination date no earlier than the UGI South COA.

Q. Why will a consolidated COA facilitate the Company's management of its environmental program?

A. The Company's consolidated COA will incorporate the sites for the South, North and Central rate districts, and will be predicated on one operating budget. This will permit the Company greater flexibility in expending resources based on risk prioritization to ensure that sites with greater risk are remediated first. Occasionally the cost of remediation exceeds expectations due to the nature of the waste, increased costs of disposal, or changing environmental standards. Having one budget will allow the Company greater flexibility to respond to unforeseen cost overruns.

Q. What types of costs does UGI Gas incur with respect to addressing MGP site conditions?

A. UGI Gas incurs costs attributed to site investigations, remediation, and site restoration as well as related PADEP oversight costs. Costs may also be incurred to obtain an environmental covenant at the site to prevent certain uses of the site, and costs associated with transferring the site to a third party (such as with a dedication for public use) once the site has been restored. Costs may also be incurred to purchase a property to secure access to investigate and remediate. Additionally, expert and legal costs are sometimes incurred in interactions with insurance carriers or other potentially responsible parties to ensure that UGI Gas's customers are only paying their equitable share of investigation and remediation costs. Costs may also be incurred to recover compensation under historical insurance policies to offset the costs that would otherwise be recovered from customers.

Q. What is UGI Gas's projected spending on the MGP program?

A. UGI Gas's average aggregate annual spending over the past three years is $4.2 million, as shown below in Table 4.

Table 4. Environmental Spend Per Year By Rate District

Year	**South**	**North**	**Central**	**Total**
2016	$659,996	$1,013,943	$535,526	$2,209,465
2017	$2,770,980	$2,629,524	$733,557	$6,134,061
2018	$2,768,395	$920,186	$530,638	$4,219,219
Total	$6,199,371	$4,563,653	$1,799,721	$12,562,745
Average	**$2,066,457**	**$1,521,218**	**$599,907**	**$4,187,582**

This amount is used in the calculation of the environmental adjustment shown in UGI Gas Exhibit A, Schedule D-8, as discussed in the direct testimony of Mr. Stephen Anzaldo (UGI Gas St. No. 3). I would note that the calculation for UGI South is conservatively low, as the amount incurred in 2016 pre-dated the effective date of the COA, which set a minimum spend amount ("floor") for UGI South at $2.5 million per year. The floor for UGI North and UGI South are $1.1 million and $1.75 million respectively.

Q. Why does environmental spend vary from the floor set by the COA?

A. While the Company uses the environmental floor as a benchmark, actual costs may exceed the minimum in certain years due to PADEP requirements, changing environmental standards, and site-specific issues such as sensitive habitat and concentration of contaminants. Additionally, since environmental spending is benchmarked by rate district, it constrains the geographic focus of UGI Gas's environmental spending, leading to underspending in certain years. In years when the

Company is unable to make its minimum spend commitments, it can avail itself of an alternative compliance pathway under each COA that permits the Company to use banked points for remedial work completed in past years.

Q. What is UGI Gas's goal for restoration of the MGP sites?

A. UGI Gas strives to restore each site for beneficial reuse that becomes an asset to the Company or the community. Because these MGP sites are located within the Company's existing service territory, restoration of the sites for beneficial reuse, whether in the form of urban redevelopment, or creation of a new public space, directly benefits UGI Gas's customers. One such example is the Mount Joy MGP site. One of the initial phases of the Mount Joy remediation resulted in the site of the former MGP being turned into a public park. It was named "Old Standby Park" in recognition of the former MGP, which was so named due to its reliable provision of energy for Mount Joy borough.

Q. How does UGI Gas quantify the environmental impact of its operations?

A. UGI Gas has been a partner in the United States Environmental Protection Agency's ("EPA") voluntary Natural Gas STAR program since its inception. Natural Gas STAR provides a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. On March 30, 2016, UGI joined with 32 other natural gas utilities to launch the EPA's Natural Gas STAR Methane Challenge Program. As a founding member of the STAR Methane Challenge, UGI Gas has committed to making and tracking emissions reductions. Participation in this program includes a commitment to replace infrastructure at a rate that reduces methane emissions by three percent a year. Lastly, starting in 2018, UGI Gas is participating in the American Gas Association's Environmental, Social, Governance, and Sustainability ("EGS/sustainability") initiative to integrate EGS/sustainability reporting metrics related to natural gas operations into a consistent industry template.

Q. Has UGI Gas quantified the environmental impact of any other of its environmental initiatives?

A. Yes. UGI Gas has converted over 90,000 households to natural gas over the past ten years. These conversions eliminate greenhouse gas emissions equivalent to removing 103,000 gasoline-fueled vehicles from the road for one year. Similar greenhouse gas emissions savings are reaped from the Company's EE&C programs, as discussed in the direct testimony of Theodore M. Love (UGI Gas St. No. 13).

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT HGB-1

Hans G. Bell, P.E.

Summary

Engineering & Operations executive with 22 years of broad experience in gas transmission and distribution operations including operations, engineering design, asset integrity management, regulatory compliance, capital budgeting, and project management.

Experience

UGI Utilities, Inc., Reading, Pennsylvania

Chief Operating Officer *2017-present*

Senior leader responsible for establishing operational strategy and for executing infrastructure programs to ensure safe, reliable, and cost-effective natural gas & electric service for a utility serving more than 700,000 customers in Pennsylvania and Maryland.

Vice President, Engineering and Operations Support *2013- 2017*

- Accountable for accelerated infrastructure replacement programs, capital budgeting (~$300M), contractor management, corrosion control, damage prevention, employee safety, engineering design, transmission & distribution integrity, regulatory compliance, training, and all related technical support functions.
- Accountable for planning and execution of annual cast iron / bare steel replacement program covering > 62 miles per year
- Primary regulatory witness and author for Long Term Infrastructure Improvement Plans
- Responsible for management and development of professional and technical support staff of over 110 employees.

AGL Resources, Naperville, Illinois

Over 17 years at AGL Resources (Nicor Gas) I advanced through positions of increasing responsibility beginning at entry level and concluding as Managing Director of Engineering.

Managing Director, Engineering *2012-2013*

- Accountable for Engineering Design, Land Management, and System Planning supporting gas transmission, storage, and distribution operations spanning 11 states serving over 4.5 million customers
- Managed capital budgets of >$200M including budget development, variance reporting, and project prioritization
- Accountable for oversight of right of way acquisitions in advance of major pipeline projects
- Developed long term investment plans for infrastructure replacement, optimization, and growth

Assistant Vice President Engineering & Chief Engineer *2011- 2012*

- Accountable for all gas utility engineering support departments with over 50 professional and technical staff including Engineering Design, Transmission Integrity, Distribution Integrity, System Planning, Geographic Information Systems, Measurement, and Technical Services (Lab)
- Accountable for Transmission & Distribution Integrity Management compliance, audits, plans, program management, and project portfolio optimization.
- Accountable for Engineering Design and project management for distribution, storage, and transmission projects from initial scope, detailed design, cost estimates, sourcing, and contract negotiation
- Managed multiple interdisciplinary project teams executing complex multi-million-dollar storage and transmission projects
- Managed regulatory relationships with State (ICC) and Federal Pipeline Safety Agencies (PHMSA). Provided technical support to incident investigations
- Developed strategic approaches to addressing pipeline safety legislation including MAOP affirmation
- Developed engineering integration plans for AGL Resources– Nicor Gas merger including, organizational design, critical process mapping, accountabilities, budgeting, and staffing

General Manager System Integrity & Chief Engineer *2007 - 2011*

- Responsible for management of multiple departments including Engineering, Transmission Integrity, Distribution Integrity, System Planning, and Geographic Information Systems
- Responsible for development and management of infrastructure capital budgets of approximately $65 million
- Managed contracts with engineering consulting firms for pipeline design, construction, survey, and professional services
- Implemented a Distribution Geographic Information System including database design, data conversion of over 34,000 miles of distribution pipe, and deployment of a mobile GIS application to all front-line workers

Manager Engineering Design *2004- 2007*

- Responsible for managing departmental capital budget in excess of $20 million annually
- Provided project management oversight to pipeline projects from concept, feasibility, budgeting, approval, planning, design and implementation
- Maintained engineering consultant relationships and negotiated service contracts
- Implemented process improvements including development of Geographic Information System (GIS) based map distribution application
- Managed pipeline construction projects, negotiated construction contracts, resolved permitting issues, and delivered project approval presentations

Project Manager – Transmission Pipeline Integrity *2003 –2004*

- Responsible for development and implementation of pipeline integrity management program to maintain regulatory compliance with the Pipeline Safety Act of 2002
- Managed GIS conversion project for 1150-mile natural gas transmission system.
- Developed risk management program for prioritization of pipeline integrity assessments in high consequence areas
- Determined pipeline assessment project schedules including long term operating expense and capital budgets

Region Manager – Distribution *2001 – 2003*

- Manager responsible for construction and maintenance activities of gas distribution utility
- Managed projects involving main installations, service installations, and leak repairs
- Measured and tracked performance of 50 personnel against productivity and safety benchmarks
- Coordinated response to emergencies including gas leaks and pipeline breaks

Supervisor of Distribution Planning *2000 - 2001*

- Supervised staff of six engineers in distribution planning department
- Coordinated hydraulic modeling studies of 34,000-mile natural gas distribution system serving over 2 million customers
- Recommended capital improvement projects required to maintain uninterrupted reliable peak day service throughout entire natural gas distribution network
- Coordinated long range planning studies and forecasts used to develop capital budgets

Project Engineer *1996 –2000*

- Managed pipeline construction and maintenance projects, supervised inspectors and company maintenance crews
- Designed plans for installation and revision of gas distribution facilities
- Reviewed highway improvement plans and worked with state transportation engineers to resolve utility conflicts

Professional Affiliations

- Licensed Professional Engineer, State of Illinois, License # 62054443
- Member Society of Gas Operators – 2015 to present
- Member Society of Gas Lighters – 2018 to present
- American Gas Association Bronze Award of Merit 2012
- Member American Gas Association Leadership Council
- Chair American Gas Association Distribution & Transmission Engineering Committee 2012 - 2013
- Speaker at PHMSA Distribution Integrity Management Workshop 2011
- Co-chair of Southern Gas Association Distribution Engineering Committee 2007-2010

Education

Keller Graduate School of Management, Chicago, Illinois

Masters of Business Administration*, Graduated with Distinction, 2000*
Concentration in Finance

University of Illinois, Champaign, Illinois

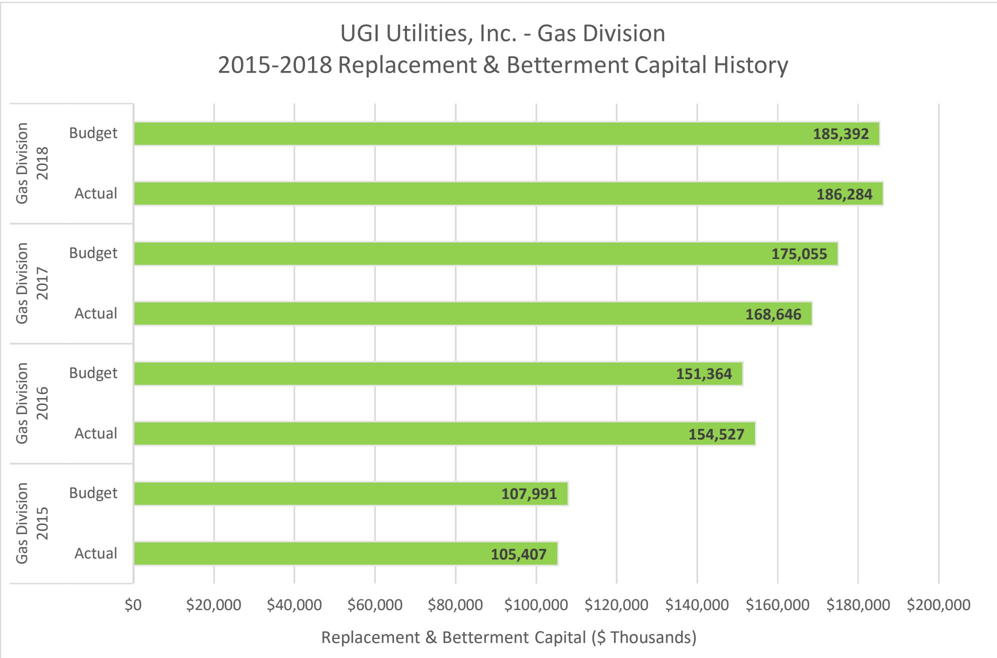
Bachelor of Science in Civil Engineering*, 1996*
Concentration in Construction Management

Previous testimony before the Pennsylvania Public Utility Commission at Dockets:

P-2013-2398833	UGI Utilities, Inc. – Gas Division, Long Term Infrastructure Improvement Plan
P-2013-2398835	UGI Central Penn Gas Inc., Long Term Infrastructure Improvement Plan
P-2013-2397056	UGI Penn Natural Gas, Inc. Long Term Infrastructure Improvement Plan
R-2015-2518438	UGI Utilities, Inc. – Gas Division, Base Rate Case
R-2016-2580030	UGI Penn Natural Gas, Inc., Base Rate Case

UGI GAS EXHIBIT HGB-2

Gas Division 2015		Gas Division 2016		Gas Division 2017		Gas Division 2018	
Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget
105,406,815	107,991,157	154,526,742	151,363,805	168,646,309	175,054,975	186,284,294	185,392,006

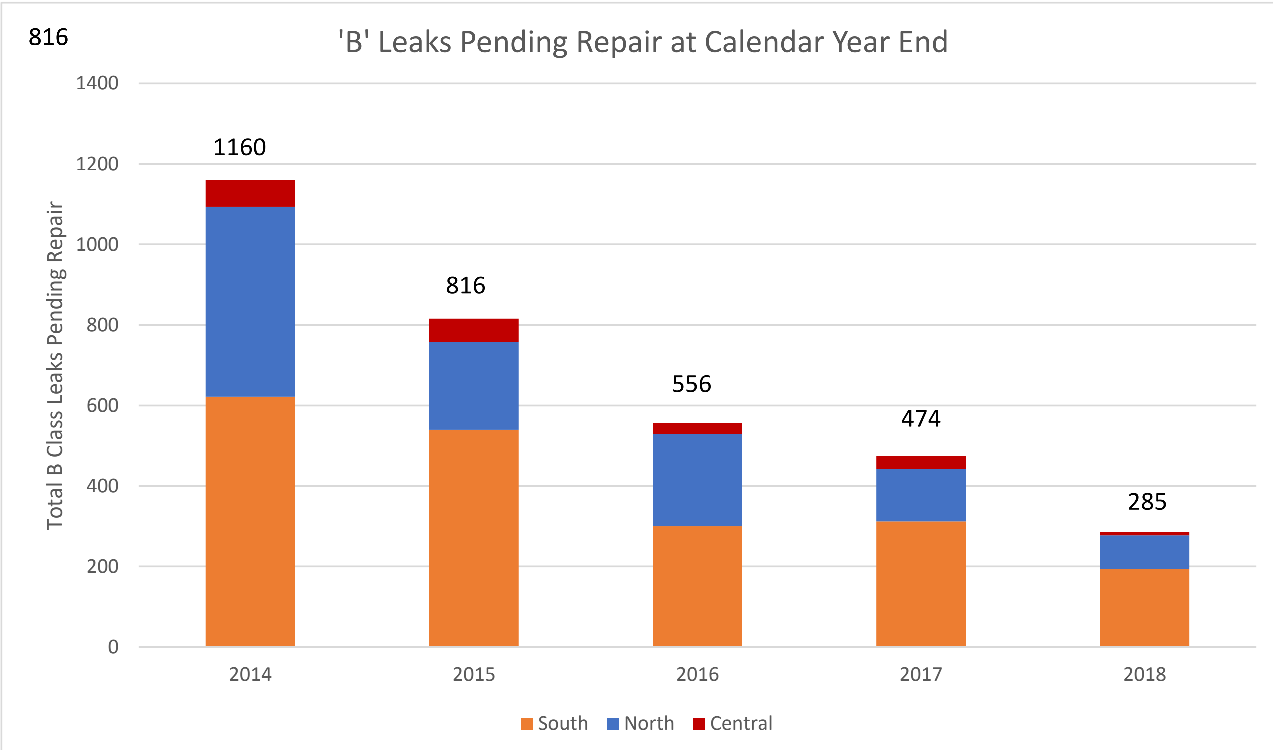


UGI GAS EXHIBIT HGB-3

UGI Utilities, Inc. - Gas Division
Budgeted Capital Expenditures

Budget Group	Division	Budget Group Description	2019	2020
41M	Gas	Main Replacement- Leaks	$7,684,559	$7,915,096
43M	Gas	Main Replacement- Relocation	12,003,256	12,363,354
44M	Gas	Main Replacement- Bare Steel	28,679,137	34,153,097
45M	Gas	Main Replacement- Cast Iron	48,365,236	49,816,193
51M	Gas	Replacement Meters / ERTS	3,031,657	3,234,200
52M	Gas	Blanket Meter Installations	390,189	412,000
54M	Gas	Maintenance-House Reg Install	146,321	154,500
58M	Gas	Replacement services not associated with main	13,660,351	14,760,351
57M	Gas	Replacement Services associated with main	32,195,265	33,161,123
01O	Gas	Misc-Plant Equipment	4,953,375	5,269,212
09O	Gas	Regulator Station Enhancements/Replacements	21,725,906	24,515,642
11O	Gas	Corrosion Related Projects	6,497,842	7,733,204
12O	Gas	Distribution System Reliability Projects	14,664,749	16,931,813
		Subtotal Budgeted DSIC Expenditures	$193,997,843	$210,419,784
40G	Gas	New Business-Mains	$7,407,772	$19,523,964
40G1	Gas	New Business-Mains - GET Gas	19,580,719	12,306,752
50G	Gas	New Business-Services	25,810,609	26,090,642
51G	Gas	New Business-Meters	3,200,000	3,200,000
52G	Gas	New Business-Meter Installation	3,414,653	3,518,321
57G	Gas	New Business-Services GET Gas	2,092,500	2,693,248
02O	Gas	Building/Building Improvements/Land acquisition	27,024,226	24,300,000
03O	Gas	Furniture and Office Equipment	1,051,000	1,082,530
04O	Gas	Fleet Capital and Related Equipment	9,300,000	9,579,000
07O	Gas	Operations Tool Blanket	2,177,300	2,242,619
53M1	Gas	Mercury Regulator Removal	2,720,000	2,801,600
01R	Gas	Remediation	270,000	288,400
49R	Gas	Cost of Removal-Mains	81,100	83,533
56R	Gas	Cost of Removal-Other	135,000	118,450
59R	Gas	Cost of Removal-Services	6,668,900	6,879,267
61R	Gas	Cost of Removal-Well Pugging	125,000	128,750
14S	Gas	IS Information Services	49,125,378	40,900,000
		Subtotal Budgeted Non-DSIC Expenditures	$160,184,157	$155,737,076
14S	Gas	HRIS (Project Connect)	$4,900,000	-
14S	Gas	UNITE Phase 3	(7,500,000)	(22,500,000)
14S	Gas	System Modifications - Energy Management Website	-	480,000
51M	Gas	Daily Metering	-	2,707,943
020	Gas	Training Center	-	15,000,000
		Subtotal Post Budget Adjustments Non-DSIC Expenditures	($2,600,000)	($4,312,057)
		Subtotal Non-DSIC Expenditures	$157,584,157	$151,425,019
		Total Capital Expenditures	$351,582,000	$361,844,803

UGI GAS EXHIBIT HGB-4


816
'B' Leaks Pending Repair at Calendar Year End
Total B Class Leaks Pending Repair
1400
1200
1000
800
600
400
200
0
1160
816
556
474
285
2014
2015
2016
2017
2018
South
North
Central

UGI GAS EXHIBIT HGB-5

Dupont Safety Culture Transformation Program
Actual and Projected Cost

	FY18 Actuals			FY19			FY20			FY21		
Scope of Work	**DSS Costs**	**UGI Costs**	**2018 Total Costs**	**DSS Costs**	**UGI Costs**	**2019 Total Costs**	**DSS Costs**	**UGI Costs**	**2020 Total Costs**	**DSS Costs**	**UGI Costs**	**2021 Total Costs**
Project Prep Work	$ 234,074	$ 35,208	**$ 269,282**									
Program Management					$ 129,171	**$ 129,171**		$ 133,046	**$ 133,046**		$ 137,038	**$ 137,038**
Safety Leadership				$ 153,000	$ 30,000	**$ 183,000**	$ 125,000	$ 30,000	**$ 155,000**	$ 100,000	$ 30,000	**$ 130,000**
Safety Governance				$ 573,000	$ 30,000	**$ 603,000**	$ 500,000	$ 30,000	**$ 530,000**	$ 425,000	$ 30,000	**$ 455,000**
Branding and Communication				$ 189,000	$ 136,000	**$ 325,000**	$ 189,000	$ 30,000	**$ 219,000**	$ 189,000	$ 30,000	**$ 219,000**
Annual Total		**FY18**	**$ 269,282**		**FY19**	**$ 1,240,171**		**FY20**	**$ 1,037,046**		**FY21**	**$ 941,038**

UGI GAS STATEMENT NO. 3 – STEPHEN F. ANZALDO

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Gas Utilities, Inc. – Gas Division

Statement No. 3

Direct Testimony of
Stephen F. Anzaldo

Topics Addressed:	**Budget Process**
	Revenue Requirement
	Operating Revenues and Expenses
	Compliance with Act 40 of 2016

Dated: January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Stephen F. Anzaldo. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. What are your responsibilities as Director, Rates and Regulatory Planning?

A. I have overall responsibility for UGI Gas and UGI Electric rate and regulatory filings before federal and state regulatory commissions, as well as the central coordination of regulatory planning. In this capacity, I report directly to the Chief Regulatory Officer of UGI. On behalf of the Rates Department, I am responsible for budgeting/financial planning for UGI, which is a joint effort with the Rates Department preparing the revenue and margin portion and the Financial Planning and Analysis Department preparing the operating expense and capital budget sections.

Q. What is your educational background?

A. I received an undergraduate degree in Accounting from St. Joseph's University and a Master's Degree in Business Administration from St. Joseph's University. I am also a Certified Public Accountant in the Commonwealth of Pennsylvania.

Q. Please describe your professional experience.

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

Q. Have you testified previously before this Commission?

A. Yes. UGI Gas Exhibit SFA-1 contains a list of those proceedings.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas in support of the Company's proposed revenue requirement. First, I will explain UGI Gas's budgeting processes (Part III). Next, I will present UGI Gas's ratemaking presentations for the historic year ended September 30, 2018 ("HTY"), future year ending September 30, 2019 ("FTY") and the fully projected future test year ending September 30, 2020 ("FPFTY"), including its principal accounting exhibits, operating expenses claims, and certain pro forma adjustments (Part IV). The Company's rate proposal in this case is predicated on its FPFTY exhibit. I will also address the Company's compliance with Act 40 of 2016 (Part V).

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

A. Yes. In addition to UGI Gas Exhibit SFA-1 mentioned above, I am sponsoring UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future), and UGI Gas Exhibit A (Historic). Other Company witnesses present testimony in support of various portions of these exhibits, including rate base (Megan Mattern, UGI Gas St. No. 4), operating revenue (David E. Lahoff, UGI Gas St. No. 8), fair rate of return (Paul R. Moul, UGI Gas St. No. 5), depreciation expense (John F. Wiedmayer, UGI Gas St. No. 7), and tax adjustments (Nicole M. McKinney, UGI Gas St. No. 11). I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

Q. What is the primary difference in the presentation of UGI Gas's principal accounting exhibits in this proceeding?

A. Prior to 2018, UGI Gas, UGI Central Penn Gas, Inc. ("UGI-CPG" or "Central Rate District"), and UGI Penn Natural Gas, Inc. ("UGI-PNG" or "North Rate District") operated as separate natural gas distribution companies ("NGDCs"). In 2018, the three NGDCs were merged into one consolidated Company, with three separate rate districts covering the former service territories of each of the three NGDCs.

As part of this base rate proceeding, the Company is proposing to consolidate the rate districts and establish unified and uniform rates. The Company's direct case in this proceeding is based on a consolidated UGI Gas claim, as shown in Exhibit A. However, information pertaining to the revenue requirements of the rate districts on a standalone basis is being provided, in order to help the Commission better understand the relative impact of our proposal. This information is found in UGI Gas Exhibit G, South Rate District (Fully Projected), UGI Gas Exhibit G, North Rate District (Fully Projected), and UGI Gas Exhibit G, Central Rate District (Fully Projected), of the filing and located in Book XII.

Q. Please describe the principal accounting exhibits used to support UGI Gas's claims in this proceeding.

A. UGI Gas Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the FPFTY, including principal accounting exhibits, rate base claims, revenue at present rates, operating expenses claims, taxes and certain *pro forma* adjustments. The FPFTY information is derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2020. UGI Gas Exhibit A (Future) is the principal accounting exhibit for the FTY, including certain *pro forma* adjustments. The future year information is derived from UGI Gas's operating and capital budgets for the 12-month period ending September 30, 2019. UGI Gas Exhibit A (Historic) is the principal accounting exhibit for the HTY, with appropriate ratemaking adjustments. The historic year information is derived from the book accounting data for the 12-months ended September 30, 2018. The future and historic schedules are provided as a benchmark for comparison with the Fully Projected claim, which, as explained above, is the basis for UGI Gas's proposed revenue increase.

Q. Please provide an overview of UGI Gas's principal accounting exhibits.

A. As noted above, UGI Gas's claims in this case are based on UGI Gas Exhibit A (Fully Projected). This presentation is comprised of four sections:

Section A summarizes UGI Gas's requested rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

Section B includes basic accounting data extracted primarily from UGI Gas's financial, accounting, operating and capital budgets, and other records. This data includes a balance sheet, a statement of net operating income and test year revenues, a schedule of expense items by cost element, and a tax expense calculation. Also included are schedules showing UGI Gas's embedded cost of debt, year-end capital structure and overall claimed rate of return.

Section C provides the elements of UGI Gas's rate base claim and how each element of that claim is derived. UGI Gas's rate base includes utility plant in service, gas storage inventory, cash working capital, materials and supplies inventory, and offsets for accumulated depreciation, accumulated deferred income taxes, and customer deposits.

Section D presents UGI Gas's revenues and expenses on a *pro forma* ratemaking basis. Necessary adjustments to budgeted levels of expense items and revenues are summarized in Schedules D-1 through D-2 and detailed in the remaining schedules. The resulting FPFTY expense and revenue levels are shown on Schedule D-3, and were used to establish UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

Q. What information is included in UGI Gas Exhibits A (Future) and A (Historic)?

A. UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2018, and the fiscal year ending September 30, 2019, respectively. This information is provided to comply with the Commission's filing requirements and provides a basis for comparing the FPFTY claims with actual and projected results from the HTY and FTY.

Q. What are the data sources for the UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic)?

A. This data is derived from the UGI Gas's books and records, and capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the FTY. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the HTY.

III. BUDGETING PROCESS

Q. Please explain UGI Gas's budgetary preparation and approval process.

A. UGI Gas's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI Gas Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget for the October 1, 2018 through September 30, 2019 fiscal year, was prepared in the spring of 2018.

The revenue portion of the budget is prepared jointly by the Marketing and the Financial Planning and Analysis Departments. This process is discussed in further detail by Mr. Lahoff (UGI Gas Statement No. 8).

Concurrently, the expense portion of the Operating Budget is prepared. Employee levels are reviewed and appropriate staffing levels are set for the upcoming fiscal year. Operating and maintenance expenses are developed by each functional manager based upon review of trends, monthly expenditure patterns, and new or changed programs. They are submitted for review and approval by senior management. UGI Gas expenses are then consolidated with charges from affiliated companies pursuant to Commission approved affiliate interest agreements to develop the budgeted Statement of Operations. The final Operating Budget is then submitted to the President and Chief Executive Officer of the Company for his review and approval, and to the Company's Board of Directors for its review and approval. Each element of the UGI Gas Operating Budget is formulated by personnel responsible for that aspect of the operation. The first and primary use of the Operating Budget is as a working tool for the management and planning of the business.

The UGI Gas Capital Budget is prepared in conjunction with the Operating Budget in a similar fashion. Additional information concerning the factors considered in establishing the UGI Gas Capital Budget is provided in the direct testimony of Hans G. Bell (UGI Gas St. No. 2). The Capital Budget is also approved by the Company's Board of Directors.

UGI Gas also has instituted a process for establishing an Operating Budget and Capital Budget for an additional fiscal year in the future, *i.e.*, the FPFTY. This process is the same as outlined above as related to the development of revenue, expense and capital budgets; however, the starting point for the FPFTY is the FTY budget. Additional assumptions are also made for emergent new business and changes in other capital expenditures based on past experience and current trends. This approach towards the fully projected future test year is consistent with the methodology used by UGI Electric in Docket No. 2017-2640058 ("UGI Electric Base Rate Proceeding"), which was approved by the Commission in that proceeding in the Opinion and Order entered on October 25, 2018.

Q. Please explain how expenses from affiliated companies are treated to develop the budgeted Statement of Operations.

A. UGI Gas incurs costs for services provided by UGI Corp., and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. All costs that can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs that cannot be directly associated with the operation of an individual operating unit are allocated to the various companies benefiting from the service by a formula internally referred to as the Modified Wisconsin Formula ("MWF"). The MWF achieves an equitable distribution of common expenses based on the relative activity and size of each operating unit to the total of all operating units. Activity is measured by total revenues and total operating expenses and size is measured by tangible net assets employed (excluding acquisition goodwill).

Q. Do you believe that the charges incurred by UGI Gas under these agreements are reasonably determined?

A. Yes. These arrangements and the methods used to allocate the costs to the companies receiving service have been reviewed by the Commission in various management audits of UGI Gas, the most recent of which was the Focused Management and Operations Audit of UGI, prepared by the PUC's Bureau of Audits, issued in April of 2012, at

Docket No. D-2011-2221061 ("Audit Report"). These methods are now incorporated into UGI's Cost Allocation Manual ("CAM") in response to recommendations of the Commission's Bureau of Audits in the Audit Report.

Q. How is this budget information used to support UGI Gas's requested revenue increase?

A. This budget information is the starting point for UGI Gas's claims and is adjusted as appropriate to reflect new information gained since the completion of the budgeting process and through application of other appropriate ratemaking principles.

IV. FULLY PROJECTED FUTURE TEST YEAR

Q. How is your discussion of UGI Gas's FPFTY revenue requirement presentation organized?

A. In Section IV.A., I present a summary of UGI Gas's FPFTY revenue requirement. In Section IV.B., I discuss UGI Gas's proposed rate base. In Section IV.C., I explain the determination of UGI Gas's revenues and operating expenses, depreciation, and income taxes.

A. FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

Q. How were the *pro forma* revenue increase and revenues at proposed rates established?

A. This calculation is shown at a summary level on Schedule A-1, column 4 of UGI Gas Exhibit A (Fully Projected). Lines 1-9 summarize the *pro forma* measure of value (rate base). Lines 10-20 show *pro forma* revenues at present rates, *pro forma* expenses, taxes at present rates, *pro forma* net operating income at present rates, and the calculated rate of return at present rates. Lines 21-23 show the increase in net operating income required to permit UGI Gas to earn its required overall rate of return of 8.31%. Application of the Gross Revenue Conversion Factor ("GRCF") on line 24 establishes the revenue increase shown on line 25 needed to generate that net operating income. Column 5 of Schedule A-1 shows the level of the revenue increase and the increase in expenses associated with the revenue increase. Column 5 of Schedule A-1 shows the revenue, expenses, and rate base at proposed rates, as well as the resulting rate of return of 8.31%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $71.090 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $871.800 million and the annual level of operating revenues of $800.710 million under existing rates. These figures are shown on line 13 of Schedule A-1 of UGI Gas Exhibit A (Fully Projected). Also, as part of the Company's proposal, it is instituting a short-term crediting mechanism to flow back the tax benefits associated with the Tax Cut and Jobs Act ("TCJA") for the period beginning January 1, 2018 through June 30, 2018, that have been established in a regulatory liability required by the Commission in its May 17, 2018 order at Docket No. M-2018-2641242, as well as in the three companion orders issued by the Commission on the same day to the pre-merger UGI natural distribution companies at Docket Nos. R-2018-3000736 (UGI Gas), R-2018-3000737 (UGI-PNG), and R-2018-3000738 (UGI-CPG). As explained in the testimony of Mr. Szykman and Mr. Lahoff

(UGI St. Nos. 1 and 8, respectively), these tax benefits with associated interest will be credited back through the existing federal tax crediting mechanism over a twelve-month period beginning with the effective date of new base rates established in this proceeding.

B. REVENUES AND EXPENSES

Q. How were revenues at present rates determined?

A. Revenues at present rates were determined by adjusting the budgeted revenues to reflect the anticipated change in the number of customers, the projected change in existing customer usage, the roll-in of revenues from the Distribution System Improvement Charge ("DSIC"), and other *pro forma* normalizing adjustments. The net effect of these adjustments is shown in UGI Gas Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of David E. Lahoff (UGI Gas St. No. 8).

Q. Please provide an overview of UGI Gas's principal accounting exhibits relative to operating expense claims.

A. UGI Gas's principal accounting exhibit is UGI Gas Exhibit A (Fully Projected), which includes a presentation for the FPFTY. Section D of UGI Gas Exhibit A (Fully Projected) presents UGI Gas's claims and necessary adjustments to budgeted levels of expense items and revenues. The *pro forma* adjustments related to expense are summarized in Schedules D-3, D-4 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI Gas's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI Gas Exhibits A (Historic) and A (Future) follow the format of UGI Gas Exhibit A (Fully Projected), but reflect data for the appropriate test years ending

September 30, 2018 and 2019, respectively. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing the FPFTY claims with prior results.

1. Summary

Q. Please describe Schedule D-1 of UGI Gas Exhibit A (Fully Projected).

A. Schedule D-1 presents a summary income statement that includes UGI Gas's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of David E. Lahoff (UGI Gas St. No. 8) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $71.090 million on line 5 in column 2.

Q. What is the level of net income at proposed rates?

A. As shown on column 3, line 21, this amount is $196.413 million. This represents a $49.870 million increase from the level under current rates ($146.543 million), as shown on line 21 in column 1 of Schedule D-1.

Q. Please describe Schedule D-2.

A. Schedule D-2 shows the development of the various line items found on Schedule D-1. Column 2 contains the Company's budgeted level of revenues and expenses for the 12-month period ending September 30, 2020. Column 3 shows adjustments to the column 2 figures, where applicable, to reflect various annualization and/or normalization adjustments. Column 4 is the sum of columns 2-3. The amount of the revenue increase and related expenses are shown in column 5 with the resulting revenues and expenses at proposed rates shown in column 6.

Q. Are there schedules showing the derivation of the adjustments shown in Schedule D-2, column 3?

A. Yes. The derivation of the various column 3 revenue adjustments is included in UGI Gas Exhibit A (Fully Projected) in summary fashion on Schedule D-3, page 1, lines 1-14, and then listed by individual adjustment on Schedule D-5. Customer charge and distribution rate revenue adjustments for each customer class are shown on lines 1-5. Gas Cost revenue adjustments for each customer class are shown on lines 6-10 and details of other revenue adjustments are shown on lines 11-14. Details for each revenue adjustment are shown in Schedules D-5 (including supporting Schedule D-5A) and are discussed in the direct testimony of witness David E. Lahoff (UGI Gas St. No. 8). Regarding *pro forma* expenses, the derivation of the various adjustments are summarized individually on pages 1-2 of Schedule D-3, lines 16-55. The details for these adjustments are found in Schedules D-4 and D-6 through D-31.

2. Operating Expense

Q. How were the claimed operating expenses for the FPFTY determined?

A. *Pro forma* FPFTY expenses are based on the budgeted level of expenses as a starting point. The budgeted data, by FERC account, was then adjusted in accordance with Commission precedent and generally accepted ratemaking principles to reflect a normal, ongoing level of operations. Schedules supporting those adjustments are found in UGI Gas Exhibit A (Fully Projected), Section D.

Q. Does UGI Gas budget its operating expenses by FERC account?

A. Yes, it does. UGI Gas budgets its operating expenses both by FERC account and by cost element, such as payroll, employee benefits, rent, etc. UGI Gas uses historic data as a basis for the distribution of expenses to each FERC account. This is shown in Schedule B-4 and is the starting point to determine the FPFTY adjusted operating expenses shown on Schedule D-3.

Q. Were each of the *pro forma* adjustments reflected on Schedule D-3 also charged to an appropriate FERC account?

A. Yes. Each *pro forma* adjustment was calculated based on the appropriate cost element and then distributed to FERC accounts directly or by using the ratio used to distribute the budgeted cost for that element.

Q. Does Schedule D-3 depict the *pro forma* expense adjustments using FERC accounts?

A. Yes. These *pro forma* expense adjustments are presented by major FERC account category. These adjustments are also shown in the Section D summary schedules.

Q. Schedule D-3 to UGI Gas Exhibit A (Fully Projected) shows an adjustment to Gas Costs in column 2. Please discuss this adjustment.

A. The detail for this adjustment is shown in Schedule D-6. This adjustment is designed to decrease purchased gas cost expense by the same amount of the gas cost revenue adjustment recommended in the direct testimony of David E. Lahoff (UGI Gas St. No. 8) and as shown on Schedule D-5, column 4, lines 7-12. UGI Gas recovers its gas costs on a dollar for dollar basis with no profit through an automatic adjustment clause mechanism pursuant to Section 1307(f) of the Public Utility Code. Therefore, the reduction in purchased gas costs of $53.698 million equals the reduction in gas cost revenue as recommended by Mr. Lahoff. Thus, the purchased gas cost expense has no effect on net operating income.

Q. Please discuss the Company Use of Fuel adjustment shown on Schedule D-4.

A. Schedule D-4 removes the cost of fuel used in operations and places it in gas supply production expenses, which is a below the line account for base rate purposes. This consists of the cost of gas used in Company operations, including gas used to heat buildings and operate city gate station heaters. This cost is being removed since it is recovered through Purchased Gas Cost rates and retainage rates charged to transportation customers.

Q. Please discuss the Salaries and Wages adjustment shown on Schedule D-7.

A. Schedule D-7 shows a $1.1 million increase to budgeted salaries and wages to reflect end of FPFTY operating conditions. This adjustment annualizes payroll expense and is distributed among the various cost accounts. Page 2 shows the development of this adjustment.

Q. Please describe the annualization adjustment.

A. This adjustment annualizes the effect of wage increases for unionized, exempt and non-exempt employees that will take place during the FPFTY. Schedule D-7, page 2, line 2 reflects the increase percentages for each classification of employee. Lines 3 through 5 indicate the percentage of the year for which the salaries and wages increases are not reflected in the budget.

Q. How did you determine the split of the budgeted salaries among the various employee classifications shown on Schedule D-7?

A. The split of the budgeted salaries among the various classifications shown on Schedule D-7, page 1 was determined using the allocations of labor for Operating and Maintenance expense in the budget. These employee groupings are the same groupings utilized in developing the labor budget. These categories were used in UGI Gas's budgeting process for the operating expense portion of salaries and wages.

Q. What adjustments are shown on Schedule D-8?

A. As the Company has in past rate cases, the three adjustments shown in Schedule D-8 are designed to enable the Company to reconcile its past Environmental Remediation expense rate recoveries with actually incurred costs and to recover a projected annual level of Environmental Remediation expense. These costs are incurred in connection with its obligations under three Consent Order Agreements with the Pennsylvania Department of Environmental Protection ("the COAs"). The Company's remediation activities under the COAs are discussed in the testimony of Hans Bell (UGI Gas St. No. 2).

Q. Please describe the first of the two remediation expense adjustments shown on Schedule D-8.

A. The first adjustment is intended to provide the Company with ratemaking recovery of ongoing annual cash expenditures pertaining to the Company's efforts primarily to remediate former manufactured gas plant ("MGP") sites in accordance with the COAs. This is the amount the Company anticipates it will spend in the FPFTY in accordance with the COAs. The annual amount is based on taking the average of the last three years of cash expenditures for remediation expense under the COAs ($4.188 million), less the amount budgeted by the Company ($3.250 million), or $938,000. As the amount budgeted for each rate district is the normalized amount UGI recovered in the most recent previous base rate case for each district, those amounts do not properly reflect the amount we are likely to incur during the FPFTY. As a result, as in past cases, the Company has chosen to normalize the expenditures based on our recent actual experience.

Q. Please describe the second of the two adjustments shown in Schedule D-8.

A. The second adjustment is designed to recover or refund, over a three-year amortization period, the difference between the amount of MGP remediation expenditures incurred under the COAs over the period since each of the rate district's most recent rate cases $6.350 million and the amount of such expenditures included for ratemaking purposes over the same period for each of the three rate districts, in accordance with the ratemaking reconciliation mechanism approved by the Commission for use by each of the three rate districts. In the instance of the UGI North Rate District, the amount it began to recover since the effective date of rate cases was $2.350 million per year; for the UGI

South Rate District, the amount was $4.000 million; and for the UGI Central Rate District, the amount was $0.

Q. How is the amount to be amortized in the second remediation expense adjustment determined?

A. This calculation is show on Schedule D-8, at lines 7-12. The unrecovered expenditures (line 9) represents the actual difference between: (a) the sum of the costs each rate district incurred in accordance with the applicable COA in the period after the effective date of new base rates established in the most recent base rate case for each of the three rate districts and any applicable regulatory assets/liabilities that had accrued in connection with the reconciliation mechanism approved by the Commission; and (b) the amount of rate recovery reflected in the rates established in the most recent base rate case.

Q. **Please discuss the third calculation at the bottom of Schedule D-8 entitled Environmental #3.**

This calculation shows the continuation of the environmental amortization that was approved by the Commission in the settlement of the most recent UGI-PNG (now the UGI North Rate District). This amortization will continue through fiscal 2022. As the amount of the annual amortization has been budgeted at the same level, there is no adjustment necessary.

Q. Which ratemaking amount will be used for determining the amount of costs subject to reconciliation in the next rate case?

A. That amount is the annual amount derived from the first of the two adjustments in Schedule D-8, or $4.188 million, which is indicative of our experience over the past three years. Any variance of actual annual expenditures from that figure, whether it represents annual spending of less than or greater than that amount, will be credited to customers (in the case of an overcollection) or recovered from customers (in the case of an undercollection).

Q. Please discuss the adjustments made in Schedule D-9.

A. As discussed in the direct testimony of Hans Bell (UGI Gas St. No. 2), UGI has recently engaged DuPont Sustainable Solutions for its assistance in reducing the potential for safety incidents on the UGI system. This amount was not included in the UGI Gas budget. The amount included in this adjustment is the amount expected to be incurred that is allocated to UGI Gas and excludes the budgeted salary and benefits of UGI personnel responsible for managing the effort with DuPont.

Q. Please discuss Schedule D-10, which shows an adjustment to Rate Case Expense.

A. Lines 1 through 3 show the rate case expense UGI Gas expects to incur in this case $1.378 million That amount is then normalized over a one-year period reflecting the expected period between future base rate case filing. The rate case expense is incurred in the FTY but is not budgeted in the FPFTY. The FPFTY budget therefore was increased by $1.378 million to reflect a normal annual level of rate case expense. We believe that

UGI Gas will make another rate case filing within a year of the conclusion of this base rate proceeding, given the significant capital investments the Company is anticipating for the year following the FPFTY. The amount associated with Rate Case Expense also includes an unbudgeted normalized amount of $54,000, representing an allocated portion of the legal expenses relating to the Office of Consumer Advocate's appeal of the Commission's final determination on the interpretation of Act 11 (fully projected future test year) and Act 40 (consolidated tax adjustment elimination) in the October 25, 2018 order in the UGI Electric Base Rate Proceeding. As these issues have a direct impact on the outcome of this base rate proceeding, UGI Gas's interest is represented in the appeal, and UGI Gas has a vested interest in the outcome of that appeal, a portion of the legal expenses of the appeal are being reflected in this case.

Q. Please elaborate on the Company's anticipated need for another rate case approximately one year from now.

A. The Company's projected capital investments in this case for the FPFTY period is $362 million, and the Company is anticipating similar capital investments for the year following the FPFTY. While some of these investments are related to growth and are self-funding, approximately $200 to $250 million relate to both infrastructure repair, replacement and improvement as well as IT system modernization investments and will require commensurate, timely, rate recovery to support. All else being equal, a growth of $200 million in rate base will equate to approximately $30 million of revenue deficiency, thus triggering the need for rate relief.

Q. What is the nature of the adjustment shown in Schedule D-11 for Uncollectible Accounts Expense?

A. Schedule D-11 adjusts the budgeted uncollectible accounts expense to reflect a longer-term average charge-off ratio. Lines 1 through 4 of Schedule D-11 develop this adjustment by showing a ratio that represents the three-year average rate of uncollectible accounts expense for the fiscal years 2016 to 2018. This ratio is used to adjust the amount of uncollectible expense in the budget to conform to the three-year average for the charge-offs. The resulting 1.348 percent ratio shown on line 4 in column 5 is applied on line 7 to the *pro forma* revenues at present rates to calculate the *pro forma* uncollectible accounts expense of $10.780 million shown in column 4 on line 7. This results in a decrease in the level of uncollectible accounts expenses for the FPFTY from the budgeted amount of $11.110 million as shown on line 5. The 1.348 percent figure is then applied to determine the level of uncollectible accounts expense at *pro forma* proposed rates through the gross revenue conversion factor, as shown in column 3, line 2 of Schedule D-35.

Q. Please explain the adjustment in the amount of $2.567 million shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 is designed to reflect an update of estimated pension expense prepared after the budget was finalized. The updated pension expense estimate is based on a more recent actuarial calculation than was used in the budget and reflects the cash to be contributed to the plan in the FPFTY. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI Gas pension in addition to the portion of the UGI Corporate Center and UGI's pension expense that is included in the expenses allocated to UGI Gas.

Q. Please discuss the *pro forma* adjustment on Schedule D-15 for Injuries and Damages.

A. The amount of expense incurred for injuries and damages in any one year can vary based on the quantity and severity of the claims. The budgeted amount for injuries and damages, $5.130 million, is shown on line 5 of Schedule D-15. This amount was compared to the three-year average injuries and damages expenses of $5.781 million calculated on lines 1-4 to arrive at an increase in injuries and damages expense of $651,000 on line 6.

Q. **Please discuss the *pro forma* adjustment on Schedule D-15 for Membership Fees.**

A. The Company budgeted the full amount of the anticipated expenses for the American Gas Association and the Energy Association of Pennsylvania in membership expenses. A portion of these industry association fees relate to lobbying activities and are excluded from UGI Gas's membership expense claim. The amounts on lines 7 and 8 of Schedule D-15 represent the percentage of expenses for lobbying activities based on the HTY applied to the budgeted expenses for each organization. Line 9 on Schedule D-15 shows the total adjustment to remove lobbying expenses and other non-allowable expenses in the amount of $24,000. Otherwise, these memberships provide the Company and its customers with operational, customer service, and other service related benefits.

Q. Please discuss the Customer Accounts Expense Adjustment.

A. This adjustment has two components: (a) a component to recover unbudgeted interest on customer deposits; and (b) an adjustment to reflect the cost of credit card fees the Company is proposing to recover in base rates rather than require customers to incur these charges directly when they pay their bills.

Q. The first component of the Customer Accounts Expense Adjustment shown on Schedule D-15 shows a $1.089 million cost item for Interest on Customer Deposits at line 18. Please explain.

A. Under the Company's tariff, the Company is required to pay interest on Customer Deposits it holds in accordance with other requirements of its tariff. As this is a typical business expense, the Company has added this amount to its expense claim that is otherwise not reflected in the Company's operations budget. It is calculated by using the average level of customer deposits anticipated for the FPFTY ($18.920 million) times the required interest rate (5.75 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and required under the Company's tariff.

Second, as discussed in the direct testimony of Daniel V. Adamo (UGI Gas St. No. 10), UGI Gas is presenting a proposal in this case to allow customers to make credit card payments at no additional cost to them. This will result in UGI Gas incurring approximate $1.447 million over the course of the FPFTY. As this proposal has developed since the time the budget was finalized, this amount was not budgeted. As discussed by Mr. Adamo, the amount of the adjustment will allow the Company to recover a reasonable level of costs associated with this proposal.

Q. What do the remaining two components on Schedule D-15 identified "Other Adjustments" represent?

A. The first of the two remaining components, in the amount of $624,000, represents the annual maintenance costs for the Daily Metering Expansion project. This unbudgeted expense is addressed in the direct testimony of Shaun M. Hart (UGI Gas St. No. 9). The second remaining component, in the amount of $53,000, is for the annual operating costs associated with the of system modifications to the Energy Management Website made in conjunction with the Company's proposal in this case to create a uniform gas transportation program. This adjustment is fully described in the direct testimony of Angelina M. Borelli (UGI Gas St. No. 12).

Q. Please discuss the *pro forma* adjustment on Schedule D-16 for Universal Service expense.

A. This adjustment normalizes the amount of Universal Services program expense recovered through the Company's CAP Rider based on the level of the Universal Service Rider charge effective at the time of the Company's filing in this matter. The CAP rider recovers the Company's Customer Assistance Plan ("CAP") Credits, and Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its Project Share program. The Company's claim represents the ongoing normalized level of costs based on anticipated levels of CAP program participation. This adjustment reduces the Company's budgeted expense by $2.781 million.

Q. Please explain the adjustment for Energy Efficiency and Conservation ("EE&C") Programs shown on Schedule D-19.

A. The first part of the adjustment shown on Line 3 reflects a $0.343 million cost reduction related to the Company's EE&C Program to reflect the updated 2020 program costs, which are lower than budgeted program costs. These program costs are discussed in the direct testimony of Theodore M. Love (UGI Gas St. No. 13). The second part of the adjustment reflects an additional expense adjustment in the amount of $3.662 million in order to normalize the amount of EE&C expense for the UGI North and South Rate Districts – those with existing EE&C Riders – to the FPFTY revenues which would be recovered through the Company's EE&C Rider based on the level of the EE&C Rider charges effective at the time of the Company's filing in this matter. Mr. Lahoff (UGI Gas St. No. 8) provides the detailed calculation of the FPFTY EE&C Rider revenue. Specifically, as the EE&C Riders are fully reconcilable riders for both the UGI Gas North and South rate districts, the EE&C adjustment assures that expenses related to those existing riders are in synch with revenues and no impact related to EE&C flows through to the revenue requirement calculation. Net EE&C expenses of $1.3 million, related to the proposed EE&C expansion to the current UGI Central Rate District, do however flow through to revenue requirement as a result of this adjustment in order to properly reflect such increased costs related to the Company's EE&C program expansion proposal.

3. Depreciation Expense

Q. How was the level of depreciation expense for the FPFTY determined?

A. UGI Gas's depreciation study is set forth in UGI Gas Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY plant in service and the applicable depreciation rates, service lives, and procedures. A summary of the budgeted depreciation expense and adjustments thereto is found in UGI Gas Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI Gas St. No. 7).

Q. Please describe the depreciation expense adjustments shown on Schedule D-21.

A. UGI Gas witness Mr. Wiedmayer (UGI Gas St. No. 7) presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $10.422 million set forth on Schedule D-21, page 2, column 3, line 64, is designed to annualize budgeted FPFTY depreciation expense in order to calculate an entire year's worth of depreciation on plant in service as of the end of the FPFTY. This schedule also shows an increase to the net negative salvage amortization of $105,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $102.722 million as shown on Schedule D-3, page 2, column 13, line 54.

4. Taxes other than Income Taxes

Q. Please describe the taxes other than income adjustments shown on Schedule D-31.

A. Schedule D-31 contains the details for taxes other than income adjustments. The adjustments to the payroll tax expenses on lines 4-6 are calculated by multiplying the ratio of tax expense to payroll expense included in the FPFTY budget by the amount of the payroll adjustment derived in Schedule D-7 to produce an adjustment to the amount of social security, Federal Unemployment Tax (FUTA) and State Unemployment Tax (SUTA) expense in the amount of $156,000. The calculation of these adjustments is shown in more detail on Schedule D-32. The other components of this schedule are supported in the testimony of Nicole M. McKinney (UGI Gas St. No. 11).

5. Income Taxes

Q. What is the purpose of Schedules D-33 and D-34?

A. These schedules show the derivation of the Company's pro forma income tax expense claim, including the normalization of the effects of accelerated tax depreciation, as discussed in the direct testimony of Nicole M. McKinney (UGI Gas St. No. 11).

6. Gross Revenue Conversion Factor

Q. What is the purpose of Schedule D-35?

A. Schedule D-35 shows the calculation of the Gross Revenue Conversion Factor used on Schedule A-1 to calculate the level of revenues required to achieve the net operating income required to generate the rate of return supported by the direct testimony of Paul R. Moul (UGI Gas St. No. 5). These additional revenues are required to recognize that uncollectible accounts expense vary with the level of revenue, and to recognize the additional state and federal income taxes attributable to the proposed rate increase.

V. ACT 40 REQUIREMENTS

Q. Mr. Anzaldo, are you familiar with Section 1301.1 of the Public Utility Code, which is otherwise known as Act 40 of 2016?

A. Yes, I am. The legislation, among other things, eliminated the use of consolidated tax savings adjustments for setting rates for public utilities in Pennsylvania, but requires a utility to demonstrate that at least 50 percent of what otherwise would have been the revenue requirement associated with a consolidated tax savings adjustment is used to support reliability or infrastructure related to the rate-base eligible capital investment.

Q. Has the Company calculated what would have been the level of a consolidated tax savings adjustment for UGI Gas under ratemaking prior to the enactment of Section 1301.1 of the Public Utility Code?

A. Yes, Company witness Nicole McKinney presents such a calculation in her testimony (UGI Gas St. No. 11). The amount of consolidated tax savings adjustment applicable to UGI Gas would have been $851,000. Applying the gross revenue conversion factor to that amount of tax expense results in a revenue requirement of $1.213 million.

Q. Does the Company's rate case claim in this case support the conclusion that it is using at least 50 percent of that revenue requirement amount to support reliability or infrastructure related capital investment?

A. Yes, as shown in Schedule C-2 and as discussed in the direct testimony of Hans Bell (UGI Gas St. No. 2), UGI Gas's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $397 million and for the FPFTY is $357 million. This expenditure level is far greater than fifty percent (50%) of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Is the Company's presentation in this filing consistent with any Commission treatment on Act 40?

A. Yes. The Company's presentation in this filing is consistent with the Commission's recent determination on Act 40 in the UGI Electric Base Rate Proceeding.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT SFA-1

Stephen F. Anzaldo
Director – Rates and Regulatory Planning

Work Experience

2015 – current	Director – Rates and Regulatory Planning UGI Utilities, Inc., Reading, PA
2011 – 2013	Director – FP&A, Mid-Atlantic Region America Water Inc., Hershey, PA
2009 – 2011	Vice President - Finance Pennsylvania American Water Inc., Hershey, PA
2006 – 2009	Treasurer Aqua America Inc., Bryn Mawr, PA
2004 – 2006	Assistant Treasurer Aqua America Inc., Bryn Mawr, PA
1996 – 2003	Accounting Manager Trigen-Philadelphia Energy Corp., Philadelphia., PA
1991 – 1996	Financial Planning Manager Trigen-Philadelphia Energy Corp., Philadelphia., PA
1985 – 1991	Corporate Accountant General Waterworks Corporation, King of Prussia, PA
1983 – 1985	Certified Public Accountant Cogen, Sklar, Levick & Company, Bala Cynwyd, PA
1981 - 1983	Certified Public Accountant Morris J. Cohen & Company, Philadelphia, PA

Previous Testimony

Default Service Plan:	Docket Nos. P-2016-2543523, G-2016-2543527
UGI Electric Base Rate Case:	Docket No. R-2017-2640058

Education

MBA - Finance from St. Joseph's University, 1998
B.S. in Accounting from St. Joseph's University, 1981
Certified Public Accountant - Commonwealth of Pennsylvania

UGI GAS STATEMENT NO. 4 – MEGAN MATTERN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 4

Direct Testimony of
Megan Mattern

Topics Addressed:	**Accounting for Historic Costs** **Rate Base Claim** **Accounting for Information Technology Costs** **Accounting for HyperCare** **PGC Revenue Adjustment** **ACH and Credit Card Fee Waiver Adjustment**

Dated: January 28, 2019

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Megan Mattern. My business address is 1 UGI Drive, Denver, Pennsylvania 17517.

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

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

Q. What are your responsibilities as Controller?

A. I have overall responsibility for the accounting functions for UGI. My duties currently include accounting, accounts payable, cash remittance and Sarbanes-Oxley ("SOX") functions and the coordination of these functions with UGI's Chief Financial Officer as well as financial accounting and reporting personnel at UGI Corp. I am also currently responsible for directing the preparation and submission of financial, accounting, and related regulatory filings with the PUC, Federal Energy Regulatory Commission ("FERC"), the United States Securities and Exchange Commission ("SEC") and the United States Internal Revenue Service ("IRS").

Q. Please describe your educational background and work experience.

A. I received a Bachelor's degree in Accounting from King's College in 2003, and a Master's degree in Business Administration ("MBA") from Wilkes College in 2007. Additionally, I have been a Certified Public Accountant ("CPA") since 2009. After graduation, I worked for Deloitte in public accounting. Thereafter, I worked for PPL Corporation in a number of positions of increasing responsibility, both on the non-regulated retail and wholesale electric generation side and on the regulated electric transmission and distribution utilities side. While at PPL, I earned my MBA degree and obtained my CPA license. I completed my career with PPL as Director, Financial Accounting and Reporting. In that position, I was responsible for preparation of all financial reports for submission to the SEC, PUC, and the FERC, SOX controls and oversight, as well as interactions with internal and external auditors. I also had significant responsibility for the preparation for and participation in PPL's rate proceedings and regulatory audits. My full educational background and work experience are set forth in my resume attached as UGI Gas Exhibit MM-1.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Gas. First, I will explain UGI Gas's accounting processes and present the actual book accounting results used in the Company's historic test year ended September 30, 2018 ("HTY") (Part II), while the future test year ending September 30, 2019 ("FTY") and fully projected future test year ending September 30, 2019 ("FPFTY") budgets are discussed in the direct testimony of Stephen F. Anzaldo (UGI Gas St. No. 3). Second, I will present the Company's claim for rate base for the FPFTY (Part III). Third, I will explain the accounting for certain Information Technology costs (Part IV). Fourth, I will explain a rate base adjustment for UNITE Phase 2 post-implementation "Hypercare" costs (Part V). Fifth, I will explain a one-time adjustment and a proposed customer credit for the recovery of purchased gas costs (Part VI). Sixth, I will explain a revenue adjustment related to the adoption of fee-free credit card processing (Part VII).

Q. Ms. Mattern, are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring those portions of UGI Gas Exhibit A (Fully Projected), UGI Gas Exhibit A (Future) and UGI Gas Exhibit A (Historic) addressing rate base and certain adjustments to rate base and operating expenses discussed later in my testimony. I am also sponsoring certain responses to the Commission's standard filing requirements as indicated on the master list accompanying this filing.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

Q. How are the accounting records of UGI Gas maintained?

A. The accounting records of UGI Gas are kept in accordance with generally accepted accounting principles ("GAAP") and the FERC's Uniform System of Accounts as required under the provisions of 52 Pa. Code § 59.42. The Company also maintains a continuing property records system in accordance with the requirements of 52 Pa. Code § 59.47.

Q. Are the books and records of UGI Gas subject to audit?

A. Yes. The books and records of UGI Gas are audited by its internal auditors and its external auditor, Ernst & Young, LLP. They are also subject to audit by the PUC.

Q. Do the continuing property records of UGI Gas reflect the original cost value of property?

A. Yes, they do. UGI Gas's plant in service, plant additions, retirements, and book adjustments have been recorded on an original cost basis in accordance with GAAP and the Uniform System of Accounts requirements.

Q. What process does UGI Gas follow to assure that property reflected in its plant accounts is used and useful?

A. UGI Gas requires field personnel to create a record when property is placed into service or retired. The information from these records is then transferred through accounting entries into the appropriate UGI Gas plant property accounts, subject to review by authorized individuals who must approve the entries and further review by internal and external auditors.

Q How was the Company's accounting process used in preparing the Company's filing?

A. The above-described accounting process was used to prepare the principal accounting exhibits used to support UGI Gas's claim in this proceeding. As discussed in the direct testimony of Company witnesses Paul J. Szykman (UGI Gas St. No. 1) and Stephen F.

Anzaldo (UGI Gas St. No. 3), the Company's claim is based on the FPFTY. The accounting data for the FPFTY was derived from UGI Gas's operating and capital budgets for the 12 months ending September 30, 2020, as shown in UGI Gas Exhibit A (Fully Projected). The accounting data for the HTY and FTY was derived from UGI Gas's books and records, and capital and operating budgets. UGI Gas Exhibit A (Future) is based on adjusted budgeted data for the FTY. UGI Gas Exhibit A (Historic) is based on adjusted experienced data for the HTY.

Q. Ms. Mattern has the Company adopted any new accounting standards since its prior rate cases that have an impact on the Company's case in this proceeding?

A. Yes. The Company has adopted Accounting Standards Codification Topic 606 ("ASC 606"), Revenue from Contracts with Customers effective October 1, 2018. ASC 606 supersedes the prior Revenue Recognition guidance (ASC 605, Revenue Recognition). As discussed in Section IV of my testimony, the Company has also adopted Accounting Standards Update No. 2018-15 ("ASU 2018-15"), which relates to cloud computing.

Q. What is the principal change to the Company's accounting practices from adoption of ASC 606?

A. Under ASC 606, the Company must recognize revenue at the time the Company satisfies each distinct or bundled performance obligation by transferring control of the promised goods or services to the customer. The Company recognizes revenue when control of the promised goods or services is transferred to the customer in an amount that reflects the consideration we expect in exchange for those goods or services. The Company generally has the right to consideration from a customer in an amount that corresponds directly with the value to the customer for our performance completed to date.

Q. How could ASC 606 impact the recognition of revenue for contracts with escalating or decreasing payments over time?

A. Under ASC 606, the recognized revenue is tied to the value of consideration over the life of the contract where the performance obligation is delivered uniformly over time. As a result, revenue must be levelized for certain multi-year contracts where the consideration differs from year to year. In other words, the total value of the consideration must be averaged over the life of the contract and recognized in the year in which the performance obligation is met, even if the contract requires the customer to pay different amounts over time for that performance obligation.

Q. How has the Company determined the impact of this new ASC?

A. The Company analyzed the impact of the new guidance by evaluating differences in the amount and timing of revenue recognition, reviewing its accounting policies and practices, and assessing the need for changes to its processes, accounting systems and design of internal controls.

Q. What will be the impact of ASC 606 on the Company’s claim in this proceeding?

A. ASC 606 will not have a material impact on the Company’s financial statements. Because of the requirement to recognize revenue equal to the performance obligation delivered to date, revenues from certain negotiated rate contracts will be reflected on a levelized basis over the length of the contract, rather than as invoiced.

Q. Ms. Mattern, please describe the impact to the FPFTY budget due to the Company's adoption of ASC 606.

A. The budgeted FPFTY revenues decreased by approximately $1.4 million as a result of the adoption of ASC 606. This decrease in revenue is due to the fact that the Company must now levelize the revenues from certain negotiated rate contracts over the life of the contract. Over time, this position will reverse and require the Company to recognize more revenue than is invoiced under the negotiated agreements.

Q. Were there any post-budget adjustments to the FPFTY as a result of ASC 606?

A. No, the budget correctly reflected the accounting for the new revenue standard.

III. FULLY PROJECTED FUTURE TEST YEAR RATE BASE

Q. With reference to UGI Gas Exhibit A (Fully Projected), please discuss how the Company's specific rate base items are determined.

A. UGI Gas's rate base presentation is shown in UGI Gas Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI Gas rate base values for the FPFTY. Column 2 indicates the schedule upon which the calculation of each of the rate base elements is found. Columns 3 and 5 show the amounts at present and proposed rates, respectively. UGI Gas's total FPFTY rate base claim is $2.4 billion. Except where otherwise noted, I will describe each of these rate base elements in greater detail below.

1. Utility Plant in Service

Q. Please explain how UGI Gas determined its FPFTY rate base value for plant in service.

A. UGI Gas's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2018, and budgeted plant additions for the years ending September 30, 2019 and September 30, 2020, less budgeted FTY and FPFTY plant retirements and certain adjustments to the budgeted additions that are shown in UGI Gas Exhibit HGB-3, which is attached to the direct testimony of UGI Gas Witness Hans G. Bell (UGI Gas St. No. 2). Mr. Bell's testimony addresses the capital addition planning process and the basis for the plant additions in the FTY and FPFTY.

Q. Please describe Schedule C-2 to UGI Gas Exhibit A (Fully Projected).

A. This schedule includes 9 pages and presents UGI Gas's FPFTY claim of $3.95 billion for used and useful gas utility plant in service, as shown on page 2, column 2, line 64. Gas utility plant enables UGI Gas to provide safe and reliable gas service to its customers.

Q. How was the gas utility plant in service amount of $3.95 billion shown on Schedule C-2, page 2, column 2, line 64 determined?

A. As noted above, this amount is based on the *pro forma* balance as of September 30, 2020. The amount includes: (1) utility plant in service as of September 30, 2018 and (2) budgeted capital expenditures expected to close to plant for the 12-month periods ending September 30, 2019 and 2020, less plant retirements during the same period, as modified by the post-budget adjustments referenced in UGI Gas Exhibit HGB-3.

Q. Please describe what information is shown on Schedule C-2, page 3.

A. This information provides a summary of UGI Gas's *pro forma* claim for utility plant in service by service category. Column 2 shows the FPFTY ending balances based on the budget; column 3 shows the net effect of the various plant adjustments; and column 4 provides the adjusted FPFTY plant in service.

Q. What information is included on Schedule C-2, pages 4-7?

A. Columns 2 and 3 on these pages show the gas plant in service balances for 2019 and 2020 based on the budget, plus the amount of plant additions budgeted as of the end of the FPFTY. Column 4 represents various plant adjustments and column 5 provides the adjusted FPFTY plant balance.

Q. Where is the information for FPFTY and FTY retirements shown?

A. Pages 8-9 of Schedule C-2 provide actual and projected plant retirements. Retirements for most plant accounts were projected by plant account by applying the average retirement rate, as a percent of additions, for the five years 2014 through 2018, to the FPFTY and FTY plant additions. For certain General Plant accounts subject to amortization accounting, retirements are recorded when a vintage is fully amortized. For these accounts, all units are retired per books when the vintage is fully amortized.

2. Accumulated Depreciation

Q. Please explain how UGI Gas determined its rate base value for accumulated depreciation.

A. UGI Gas started with accumulated depreciation as of September 30, 2018, added the budgeted level of depreciation expense for the FTY and FPFTY, and calculated the impact of the FTY and FPFTY plant retirements and a provision for net salvage as shown on Schedule C-3. The depreciation rates and test year expense levels are discussed in the direct testimony of John F. Wiedmayer (UGI Gas St. No. 7), with the underlying FPFTY depreciation analysis provided in UGI Gas Exhibit A (Fully Projected).

Q. Please describe UGI Gas's accumulated depreciation claim.

A. UGI Gas's accumulated depreciation claim is shown on Schedule C-3 of UGI Gas Exhibit A (Fully Projected). This schedule, containing 11 pages, presents the accumulated provision for depreciation as of September 30, 2020, distributed among the various FERC accounts. The total amount for accumulated depreciation, $1.073 billion, is summarized on pages 1-2 of this schedule. That amount is reflected on line 2 of the measure of value summary on Schedule C-1.

Page 3 shows the *pro forma* FPFTY level of accumulated depreciation distributed to the various plant categories. Pages 4-5 show the details of the accumulated depreciation by FERC account for fiscal year 2019 and 2020 based on budget plus adjustments to arrive at the FPFTY balance. Pages 8-9 show the negative net salvage amortization by FERC account. Pages 10-11 include the salvage amounts for the FPFTY. All of these amounts are included in the FPFTY accumulated depreciation calculations. The amortization of negative net salvage was calculated using a 5-year amortization schedule in accordance with Commission precedent.

Q. Are there adjustments to the budgeted amounts for accumulated depreciation?

A. Yes. Similar to the plant assets shown on Schedule C-2, the accumulated depreciation must also be reduced by the accumulated depreciation on common assets allocated to UGI's Electric Division. These adjustments are shown in column 3 on Schedule C-3, page 3 and column 4 on Schedule C-3, pages 4 and 5.

3. Cash Working Capital

Q. Please explain how UGI Gas determined its rate base value for cash working capital ("CWC").

A. CWC is the capital requirement arising from the difference between (1) the lag in the receipt of revenue for rendering service and (2) the lag in the payment of cash expenses incurred to provide that service, as shown in Schedule C-1. A detailed analysis of UGI Gas's CWC requirements is provided in Schedule C-4.

Q. What data is shown on page 2 of Schedule C-4?

A. Page 2 summarizes the derivation of UGI Gas's revenue collection lag and overall expense payment lag. The revenue lag days are shown on line 1 and the expense lag days are shown for each component on lines 3-5. The net lag in the collection of revenue is 25.34 days as shown on line 8. This number is then multiplied by the average daily operating expense balance on line 9 to arrive at a base cash working capital amount for O&M expense of $35.127 million. The average daily expense balance of $1.386 million shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense of $505.811 million, as shown on line 6 of column 2, by the number of days in a year, or 365. I will describe the other components of the CWC claim when I discuss the related schedules.

Q. Please describe the revenue lag calculation shown on Schedule C-4, page 3.

A. The total revenue lag days (line 23) were determined by dividing the annual revenue billed during the year (line 18, column 3) by the average month-end accounts receivable balances for the thirteen months ended September 30, 2018 (line 17, column 2). This results in an accounts receivable turnover rate of 9.09 (line 19, column 4), which is equivalent to 40.15 lag days (line 20, column 5) (*i.e.*, 365 divided by 9.09 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 1.53 day lag between the meter reading day and the day bills are sent out and recorded as revenue and accounts receivable by the Company and (2) the 15.21 day service lag, which is the time from the mid-point of the service period until the meter reading date. This calculation results in a total revenue lag of 56.89 days.

Q. How was the mid-point of the service period calculated?

A. The mid-point of the service period is equal to the number of days in an average service month (365 days divided by 12, or 30.42 days) divided by two (15.21 days).

Q. How are the payroll expense lags for the CWC claim calculated?

A. This calculation is shown on page 4 of Schedule C-4, lines 1-6. The payroll amounts shown there reflect the payroll for the FPFTY, which is shown on Schedule D-7. The lag periods for union and non-union payroll are shown separately on page 4 of Schedule C-4, lines 1-2 with the same bi-weekly pay period.

Q. How were the lag days associated with the purchased gas costs shown on Schedule C-4, page 4, line 8 calculated?

A. This calculation is shown on page 6 of Schedule C-4, and is based on a review of gas purchases during the 12-month period of October 2017 through September 2018. The total dollar amount of gas purchased during this period was $421.737 million, and the average payment lag equaled 36.41 days. The payment lag was determined using the midpoint of the service period for each of the payments and the payment date for each, averaged over the 12-month study period.

Q. How was the Other Expense payment lag, shown on Schedule C-4, page 4, line 21, calculated?

A. The calculation is shown on page 5 of Schedule C-4. The average payment lag for all remaining expenses was derived from data over twelve months, as shown in more detail on page 5 of Schedule C-4. A list of all cash disbursements during each of these months was used in a format that shows the payee, the invoice date, the amount of the disbursement, the date the payment was made, the account to which the disbursement was charged and other data associated with the disbursements. As shown on page 5, lines

1-24, each month's listing contained numerous cash disbursements. Once the raw payment data was assembled, the dollar days were determined by multiplying the amount of the disbursement by either (i) the number of days from invoice date until bank clearance for wire payments, or (ii) the number of days from the invoice date until check date, plus seven days for payments made by check. Disbursements were eliminated if they were included in another calculation (*e.g.*, gas commodity purchases), capital items, and other non-expense amounts. The lag for Other Disbursements is calculated on Schedule C-4, page 4, line 22 and brought forward to Schedule C-4, page 2, column 3, line 5.

Q. Please explain how the interest payment amount included on line 2 of Schedule C-4, page 1 was determined.

A. The calculation of this amount is shown on Schedule C-4, page 7. This calculation measures the lag associated with the payment of interest on outstanding debt. The *pro forma* annual interest expense shown on line 4 is divided by 365 to obtain the daily interest expense of $138,000 shown on line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $4.757 million, as shown on line 9. This amount is then included on page 1, line 2 of Schedule C-4.

Q. How was the working capital requirement for tax payments shown on line 3 of Schedule C-4, page 1 determined?

A. This calculation is shown on page 8 to Schedule C-4. Separate calculations are made for federal income tax, state income tax, PA Property Tax and PURTA. Each of these calculations is based on anticipated FPFTY tax payments and an April 1 mid-point of annual service. The result for each of these components is shown and summed in column 10 to derive the net working capital allowance for tax payments.

Q. How was the working capital allowance for pre-payments derived?

A. That amount is calculated on page 9 of Schedule C-4 and represents the thirteen-month average of actual pre-paid amounts for each month ended from September 2017 through September 2018.

Q. What is the total amount of the Company's cash working capital claim?

A. UGI Gas's claim for CWC is $39.756 million. This amount is shown on Schedule C-4, page 1, line 5; Schedule C-1, line 4; and on Schedule A-1, line 4.

4. Gas Storage Inventory

Q. Please explain how the rate base value for gas storage inventory was determined.

A. Gas stored underground represents gas volumes stored in facilities or in storage fields owned by interstate pipeline or storage companies with whom UGI Gas contracts for capacity. As is typical for most natural gas distribution systems, UGI Gas purchases storage gas throughout the year for use primarily during the winter heating season. UGI Gas's claim for gas storage inventory is based on a 13-month average book value for the period ending September 2020 as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $25.736 million, as shown on Schedule C-5, line 16, column 4. This amount is also used in Schedule C-1, line 5 and Schedule A-1, line 5.

5. Accumulated Deferred Income Taxes (ADIT) and Excess Deferred Federal Income Taxes (EDFIT)

Q. Please explain how the rate base values for ADIT and EDFIT are calculated.

A. The Company's determination of its rate base value for ADIT and EDFIT is shown on Schedule C-6 and is discussed in the direct testimony of Nicole McKinney (UGI Gas St. No. 11).

6. Customer Deposits

Q. Please explain how the rate base value for customer deposits is calculated.

A. The customer deposit offset is $18.920 million as shown on Schedule C-1, line 7 and on Schedule A-1, line 7. The balance at the end of the HTY was used to determine the rate base offset for customer deposits.

7. Materials and Supplies Inventory

Q. **What is the rate base claim for materials and supplies inventory?**

A. UGI Gas maintains various materials and supplies in inventory for use in its operations. Its claim for those items is $13.666 million, as shown on Schedule C-1, line 8, is based on the average inventory for the 13-month period ending September 30, 2018. This amount represents the balance at the end of the HTY as shown on Schedule C-8. This value is also shown on Schedule A-1, line 8. The Company will update this average during the course of this proceeding.

IV. CAPITAL TREATMENT OF CERTAIN INFORMATION TECHNOLOGY COSTS

Q. Ms. Mattern, how does the Company currently account for cloud-based services?

A. In recent years the Company has sought and received Commission approval to capitalize certain development costs for cloud-based information systems. In 2017, the Company received Commission approval in the UGI Penn Natural Gas, Inc. ("PNG") base rate proceeding at Docket No. R-2016-2580030 to capitalize the costs incurred to prepare data bases for cloud-based services. At the time, GAAP accounting guidelines would have considered such costs to be expenses. However, the National Association of Regulatory Utility Commissioners ("NARUC"), in a Resolution adopted on November 16, 2016, encouraged state regulators to consider whether cloud computing costs should be capitalized similar to the regulatory accounting treatment for on-premise solutions. NARUC cited the enhanced security and flexibility of cloud-based systems and noted that the disparity in accounting treatments disincentivized utilities from investing in cloud-based solutions and realizing their benefits.[1]

In approving the Joint Petition for Settlement of All Issues in the PNG base rate proceeding, Chairman Gladys M. Brown praised the parties' agreement to capitalize such costs, stating, in pertinent part:

> In particular, I am encouraged by the terms contained in paragraph 26 of the settlement, which permit UGI to capitalize the development costs for cloud-based information systems. This accounting treatment is wholly consistent with the resolution passed by the National Association of Regulatory Utility Commissioners related to the regulatory treatment of cloud computing arrangements.

[1] *"Resolution Encouraging State Utility Commissions to Consider Improving the Regulatory Treatment of Cloud Computing Arrangements"* Adopted by the NARUC Committee of the Whole on November 16, 2016.

> The information technology landscape is ever-evolving. With this comes an equally significant evolution in the expectations of utility customers. It is the duty of Commissioners to construct a regulatory climate which accommodates new technologies and capabilities in order to provide utilities with the tools necessary to satisfy and empower their customers. Permitting for the capitalization of cloud computing helps to align the interest of regulated utilities with the expectations of 21st century customers.

In 2018, the Company similarly received Commission approval in the UGI Electric base rate proceeding at Docket No. R-2017-2640058 to capitalize the costs incurred to prepare data bases for cloud-based services. In a Joint Stipulation, all parties agreed to capitalize those costs. In approving the Joint Stipulation, the Commission noted that the presiding administrative law judges had concluded that UGI Electric's use of cloud-based services:

> will offer many advantages to traditional on-premise software such as enhanced security, reliability, and flexibility. The databases created for the cloud-based services will also be used by UGI to optimize various aspects of the utility service provided to its customers over, at a minimum, the life of the cloud-based service agreement… [and] that UGI will retain ownership and control of these databases after the close of the cloud-based service for which they are being created and likely will use the information in subsequent applications.[2]

Therefore, the ALJs found, and the Commission agreed, that it is appropriate for the costs of these cloud-based services to be capitalized and depreciated over their service life.[3]

Q. What specific cloud-based services assets were permitted to be capitalized in the PNG and UGI Electric base rate proceedings?

A. As a result of the PNG base rate proceeding, the Company was permitted to capitalize an allocable portion of SAP SuccessFactors, a Human Resource Information System that

[2] *PaPUC v. UGI Utilities, Inc. – Electric Division,* Docket No. R-2017-2640058 (Opinion and Order entered October 4, 2017), at p. 16.
[3] *Id*. at p. 36-37.

includes performance and learning management, benefits and payroll, and an allocable portion of SAP Fieldglass Vendor Management system, a contractor management program. As a result of the UGI Electric base rate proceeding, the Company was permitted to capitalize an allocable portion of SuccessFactors and Fieldglass as well as Concur, an Expense Management System, and Salesforce, a Marketing Analytics tool.

Q. Have there been any recent updates to GAAP with respect to Cloud Computing that impact the capitalization of these implementation costs?

A. Yes. On August 29, 2018 the Financial Accounting Standards Board issued ASU 2018-15, an update to the Accounting Standards Codification, which is the source of authoritative GAAP, relating to the accounting for costs incurred to implement cloud computing.[4] The amendments in the update are effective for annual reporting periods beginning after December 15, 2020. However, early adoption of the amendments is permitted for all entities. UGI adopted this accounting treatment as of October 1, 2018, prospectively, for all implementation costs associated with service contracts for cloud computing arrangements.

Q. How does the GAAP update impact the capitalization of cloud computing implementation costs?

A. ASU 2018-15 permits the capitalization of implementation costs that was endorsed by NARUC and approved in the recent PNG and UGI Electric base rate proceedings that I

[4] Accounting Standards Update No. 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40); Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*

discussed previously. It specifically directs the capitalization of certain costs incurred during the application-development stage, and the capitalization of certain costs during the post-implementation-operation stage that result in enhanced functionality to the hosted solution. Since the Company adopted the ASU 2018-15 change on October 1, 2018 this accounting treatment is reflected in the FTY and FPFTY accounts. The Company also included in the FTY and FPTY rate base claim costs that were incurred prior to October 1, 2018, consistent with the accounting treatment permitted in the prior rate cases discussed above.

V. <u>CAPITAL TREATMENT FOR UNITE PHASE II HYPERCARE</u>

Q. Ms. Mattern, please explain what is Hypercare?

A. Hypercare is another term for the typical post-implementation support following the deployment of a project to ensure that the new system/function operates as planned. Hypercare is essential for business continuity because project deployment methodology and system constraints often do not allow for a period of parallel system operation and testing prior to implementation. As part of an IT system implementation, whether a home-grown, perpetual use, or cloud-based system, there is a period of support after the system's in service date that requires internal and external resources to be on-site (or on call) to support system issues, or other immediate support needs as required within the fully-deployed and operational system. Hypercare may also include developing and implementing additional system functionality that was not completed at the implementation date.

Hypercare will require both internal and external resources. The Company has partnered with a system integrator for the UNITE Phase II project. The system integrator has built this post- implementation support into its contract price with UGI. Internal resources also will be needed to support the post-go-live effort. Based on the Hypercare staffing model provided by the system integrator, and the April 15, 2019 in-service date for UNITE Phase II, approximately $2.5 million in external costs will be incurred for this activity. There are also approximately $1.875 million in internal labor costs budgeted to Hypercare. Some of the cost incurred for Hypercare will be for activities such as additional functionality, while other costs will be attributed to troubleshooting.

Q. How does the Company propose to account for Hypercare?

A. The Company is requesting permission to capitalize Hypercare costs and amortize them over a fifteen (15) year period which is consistent with the amortization of UNITE Phase II capital costs.

Q. Why is it reasonable to capitalize Hypercare?

A. Some portion of these costs can already be capitalized under GAAP, such as modifications to existing software that result in additional functionality. However, other post-implementation support efforts such as break/fix resources or resources dedicated to troubleshooting issues cannot currently be capitalized under GAAP. Additionally, some Hypercare work could be classified as both troubleshooting and the addition of new functionality. Both types of efforts are necessary to enable the system to reach its full functionality. The Company therefore seeks Commission approval to capitalize all Hypercare costs associated with UNITE Phase II, which are expected to be incurred over a three-month period post implementation. An alternative to utilizing a Hypercare period for a system implementation would be to run parallel testing operations for an extended period prior to implementation. Parallel testing costs can be capitalized under GAAP and can be as costly, if not more costly, than a Hypercare solution.

Q. Has the Company made an associated adjustment to operating expense to remove the Hypercare costs that the Company proposes to capitalize?

A. No. These costs were budgeted and reflected as capital in the FTY and FPFTY.

VI. <u>ADJUSTMENT FOR PURCHASED GAS COSTS ERROR</u>

Q. Does the Company propose any ratemaking adjustments as a credit to the recovery of purchased gas costs in this case?

A. Yes. In 2018, the Company discovered a mathematical error in a purchased gas cost workpaper that resulted, over time, in an overcollection for UGI Gas Central Rate District customers and a slight undercollection for UGI Gas North Rate District customers. These errors were not previously identified by our accounting processes, in purchased gas cost rate proceedings, or in PUC Audit Staff reviews of our purchased gas cost recoveries. To address the error, the Company will be crediting the net overcollection in the amount of $5,418,673 to customers through the Purchased Gas Cost charge starting on the effective date of new base rates.

VII. ADJUSTMENT FORCREDIT CARD AND ACH FEE WAIVER

Q. Is the Company making a ratemaking adjustment to revenue due to its waiver of third-party vendor fees for telephonic and web-based ACH and credit card transactions?

A. Yes. The Company is making an upward adjustment to its revenue requirement in the amount of $1.44 million to reflect third-part vendor fees for ACH and credit card transactions, as discussed in more detail in the testimony of Daniel V. Adamo (UGI Gas St. No. 10). This amount will be collected in base rates in lieu of customers paying these fees directly to an outside vendor for processing these transactions.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI GAS EXHIBIT MM-1

Megan Mattern, C.P.A., M.B.A.

Employment Experience:

UGI Utilities, Inc., Reading, PA (May 2016 - Present)
Controller and Principal Accounting Officer

- Officer of the company, responsible for financial accounting, tax accounting, asset accounting, accounts payable, and cash operations for rate-regulated utility with revenues of $1 billion.
- Audit Committee reporting on status of financial reporting and internal controls.
- Responsible for external SEC reporting for standalone segment; extensive knowledge of GAAP, including ASC 980 (Regulated Operations) and FERC accounting guidance.
- Responsible for the preparation and filing of regulatory reports including the FERC Form 1 and 3Q and the PUC Annual Report.
- Responsible for the implementation of new accounting guidance including Revenue Recognition (ASC 606), Leases (ASC 842), and the 2017 Tax Cuts and Jobs Act.
- SOX responsibility for entire Company; Extensive SOX 302 and 404 knowledge including the application of the COSO framework, controls over information technology general controls.
- Oversight of accounting and SOX impact of $80M SAP Customer Information system and $50M ERP system.
- Significant responsibility in managing regulated rate case proceedings and audits including testifying in rate proceedings.

PPL Electric Utilities, Allentown, PA (2014 – May 2016)
Director – Financial Accounting & Reporting (March 2014 – May 2016)
Manager – Financial Analysis and Reporting (September 2011 – March 2014)

PPL Corporation, Allentown, PA (September 2004 – September 2011)
Various Positions with increasing responsibility, most notably Senior Team Lead Financial Accounting

Deloitte, Philadelphia, PA – (August 2003 – September 2004)
Staff Accountant

Previous Testimony:

UGI Penn Natural Gas, Inc. base rate proceeding:	Docket No. R-2016-2580030
UGI Utilities, Inc. – Electric Division base rate proceeding:	Docket No. R-2017-2640058

Education:

Wilkes University, Wilkes-Barre, Pennsylvania, April 2007 Overall GPA: 3.9
Masters of Business Administration (M.B.A.) The Jay S. Sidhu School of Business & Leadership

King's College, Wilkes-Barre, Pennsylvania, May 2003 Overall GPA: 3.9
B.S. Degree in Accounting, Honor's Program, Summa Cum Laude

Adjunct Professor, **Kutztown University**, teacher of Accounting for 2009-2010 School Year

Professional License:

Certified Public Accountant in Pennsylvania

UGI GAS STATEMENT NO. 5 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 5

Direct Testimony of
Paul R. Moul, Managing Consultant
P. Moul & Associates, Inc.

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

Dated: January 28, 2019

<u>UGI Utilities, Inc. - Gas Division</u>

Direct Testimony of Paul R. Moul

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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
CCR	Corporate Credit Rating
CE	Comparable Earnings
DCF	Discounted Cash Flow
FERC	Federal Energy Regulatory Commission
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
LDC	local distribution companies
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
OCI	Other Comprehensive Income
P-E	Price-earnings
PUC	Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Return on the market
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 Gas	UGI Utilities, Inc. – Gas Division
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
ytm	Yield to maturity

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 Appendix A, 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 UGI Utilities, Inc. – Gas Division ("UGIU Gas" 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 Exhibit B, which is a multi-page document divided into fourteen (14) schedules.

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 an 8.30% overall rate of return which includes an 11.25% rate of return on common equity. My 11.25% rate of return on common equity includes recognition of the exemplary performance of the Company's management, and 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 cost of equity determination should be viewed in the context of increasing capital costs revealed by rising interest rates and the need for supportive regulation at a time of increased infrastructure improvements now underway for the Company. Moreover, as I will describe below, the Company faces more risk with the passage of the Tax Cut and Jobs Act of 2017 ("TCJA") signed into law on December 22, 2017.

My overall rate of return recommendation is determined by using the weighted average cost of capital. 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 which 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
Total Debt	45.20%	4.73%	2.14%
Common Equity	54.80%	11.25%	6.17%
Total	100.00%		8.31%

This overall rate of return is applicable to the September 30, 2020, fully projected future test year ("FPFTY") and the period that the Company's proposed rates will be effective.

DIRECT TESTIMONY OF PAUL R. MOUL

Q. What factors have you considered in the determination of the Company's cost of equity in this proceeding?

A. The Company is a division of UGI Utilities, Inc. ("UGI Utilities"), a wholly-owned subsidiary of UGI Corporation ("UGI" or the "Parent Company"). The Company provides natural gas distribution service to approximately 642,000 customers in forty-four eastern and central Pennsylvania counties. The Company's service territory contains several production centers for basic industries involved in steel and aluminum manufacturing and fabrication chemicals, and food processing. Throughput to on-system customers in 2018 was represented by approximately 23% to sales customers and approximately 77% to transportation customers. The significant portion of the Company's throughput to industrial customers makes the Company a much higher risk utility as compared to the Gas Group. The Company obtains its natural gas supplies from producers and marketers and has transportation arrangements through connections to six interstate pipelines. The Company has storage arrangements for natural gas inventory. UGI Utilities, Inc. also provides electric delivery service, through its Electric Division, to approximately 62,000 customers in portions of Luzerne and Wyoming Counties.

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 a natural gas 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 11.25% represents a reasonable cost of equity, which is consistent with well recognized principles for determining a fair rate of return.

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 nine (9) natural gas companies. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of ten companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. I eliminated one company from the Value Line group. UGI Corp. was

[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).

removed due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. I will refer to the nine companies as the "Gas Group" throughout my testimony. The companies are identified on page 2 of Schedule 3. In the recent Quarterly Earnings Report approved by the Commission on October 25, 2018, the Gas Distribution Company Group included six companies that are part of my Gas Group. I will make a separate calculation of the cost of equity using the six-company subgroup (the "Subgroup").

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

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company has become increasingly problematic. The use of average data for a portfolio of companies reduces the effect that anomalous results for an individual company may have on the rate of return determination. 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.

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. 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.

	Gas Group	Subgroup
DCF	11.19%	11.58%
Risk Premium	11.50%	11.50%
CAPM	11.98%	12.07%
Comparable Earnings	12.75%	12.75%

From these measures, I recommend a cost of equity of 11.25%. My recommendation is on the conservative side for UGIU Gas because it is based on the Gas Group that does not have the Company's high-risk attributes related to its high level of industrial throughput. It does provide recognition of the performance of the Company's management. Mr. Szykman's testimony in UGI Gas Statement No. 1 demonstrates that the Company ranks high in customer service and management effectiveness. In recognition of its outstanding performance, the Company should be granted an opportunity to earn an 11.25% rate of return on common equity. My 11.25% cost of equity recommendation includes 25 basis points or 0.25% recognition for the exemplary performance of the Company's management. 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. Along these lines, the Company is spending considerable amounts of capital on main replacements and this will put a strain on performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.25% rate of return on common equity.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of the natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability, and on conservation and energy efficiency. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues and extension and expansion requests, which have led to increased external capital requirements.

Q. Does the Company face competition in its natural gas business?

A. Yes. The Company's close proximity to the Marcellus Shale production area provides additional risk for it compared to the companies in the Gas Group. Natural gas generally faces significant competition from alternative energy sources. The Company faces direct competition from electricity, fuel oil, and propane in its service territory. Propane and fuel oil have an advantage because they are not inhibited by regulatory constraints when conducting marketing and pricing their services. This situation is unlike that of UGIU Gas, where specific thresholds must be satisfied for system expansions, where promotional activities are constrained and prices are regulated. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices. Further, the Company has identified twenty-four (24) customers that could potentially bypass its system.

Q. Are there specific factors influencing the Company's risk profile?

A. Yes. The Company's risk profile is strongly influenced by throughput delivered to large competitive market customers. Large competitive market customers represent over 50% of throughput, but these customers represent about one-half of one percent of total customers. Moreover, the Company's top ten customers represent 185.4 million Mcf of total throughput, or about 55.8%. Electric generation, manufacturing, chemicals, and food processing are among these customers. Steel and aluminum manufacturing and fabrication face a number of challenges, including international competition, increased costs, and fluctuating demand for products. Industrial sales are generally higher in risk than sales to other classes of customers. Success in this segment of the Company's market is subject to the business cycle and the price of alternative energy sources. Moreover, external factors can also influence the Company's sales to these customers which face competitive pressures on their own operations from other facilities outside the Company's service territories.

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

A. With customer demand for the Company's service at high levels, the Company is faced with the requirement to invest in new facilities to meet growth and to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade existing facilities. The Company has approximately 1,037 miles of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2017. The Company also has 11,207 of its services constructed of unprotected steel. The continuing costs for upgrading the Company's pipe system will elevate the level of construction expenditures. In the situation where additional capital investment is required to serve new customers, supportive regulation represents a necessary prerequisite for the Company to actually achieve a fair rate of return and attract new capital on reasonable terms.

For the future, the Company estimates that its construction expenditures will be:

Year	Capital Expenditures
2019	$ 386,000,000
2020	$ 384,000,000
2021	$ 400,300,000
2022	$ 418,300,000
Total	$ 1,588,600,000

During the 2019-2022 period, gross construction expenditures will represent an approximate 62% increase ($1,588,600,000 ÷ $2,541,768,000) in net utility plant, including construction work in progress, from the level at September 30, 2018.

Q. Is the Company's risk also affected by the substantial decline in usage per customer?

A. Yes. Despite adding a substantial number of new customers, usage per residential heating customer continues to decline over time as discussed in the testimony of Mr. Lahoff (UGI Gas Statement No. 8). Company analysis indicates that this decline will continue, particularly with the implementation of a new energy conservation plan. This plan will provide many benefits to customers and to the public, but can be expected to further reduce customer usage.

Q. Are you aware that there is a Distribution System Improvement Charge ("DSIC") available to natural gas utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company has utilized the DSIC in the past. The cost of capital for UGIU Gas, however, is not affected by the DSIC. I say this because most of the proxy group companies (i.e., eight of nine companies) whose data has been used to develop the cost of equity for UGIU Gas in this proceeding have a DSIC or similar infrastructure rehabilitation mechanism. Indeed, Atmos Energy, Chesapeake, New Jersey Resources, NiSource, Northwest Natural Gas, South Jersey Industries, Southwest Gas, and Spire make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever benefit is derived from the DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. You indicated previously that the new federal income tax law changes will add to the Company's risk. Please explain.

A. There are several major financial consequences arising from the changes in the federal income tax law that will negatively impact the Company. First, a lower federal income tax rate will lower the Company's pre-tax interest coverage and will reduce credit quality and increase risk. For example, page 1 of Schedule 1 shows that with the new marginal federal corporate income tax rate the pre-tax interest coverage will be 5.06 times at proposed rates. Under the old 35% marginal federal corporate income tax rate, the pre-tax interest coverage would have been 5.93 times. When pre-tax interest coverage declines, credit quality falls and credit risk increases. This assumes no other changes in tax provisions that may also impact the Company's financial condition and credit quality. Second, with a lower marginal federal corporate income tax rate, the Company's return variability will increase, thereby increasing its business risk. When the federal corporate income tax rate was formerly 35%, investors only needed to absorb 65% of any changes in revenues and expenses. At a 21% federal corporate income tax rate, investors will need to absorb 79% of changes in revenues and expenses. That is to say, the reduced federal income taxes will make investor returns more variable than formerly, thereby increasing the Company's risk. Third, utilities will require more investor supplied capital to fund their construction programs because the level of deferred taxes will decline and because the new tax law eliminates bonus depreciation. This will also impact another credit metric, revealed by the percentage of internally generated funds to construction. This percentage will decline with the new lower income tax rate. In response to these financial challenges caused by the new lower federal corporate income tax rate, there may be the need to reduce the percentage of debt in a utility's capital structure to respond to higher business risk and weaker credit quality measures.

Q. How should the Commission respond to the issues facing the natural gas business and in particular UGIU Gas?

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has abnormal risks associated with its large throughput to industrial customers. Another risk is declining usage per customer discussed in the testimony of Company witness Mr. David E. Lahoff (UGI Gas Statement No. 8).

<u>FUNDAMENTAL RISK ANALYSIS</u>

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 UGI Utilities to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Gas Group.

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 Gas Group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, New Jersey Resources Corp., NiSource, Inc., Northwest Natural Holding Co., ONE Gas, Inc., South Jersey Industries, Inc., Southwest Gas Holdings, and Spire, Inc. The subgroup (the "Subgroup") that I used contains six companies and was obtained from the Commission's Quarterly Earnings Report and excluded ONE Gas, Southwest Gas and Spire.

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 Gas Group, and the S&P Public Utilities?

A. Presently, the Company's Long Term ("LT") issuer rating is A2 from Moody's and A- from Fitch. 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 Gas Group, which has an average A2 and A- credit rating from Moody's and S&P, respectively. The average ratings for the Subgroup used in the Quarterly Earnings Report are the same. For the S&P Public Utilities, the average composite credit rating is 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.

Q. How do the financial data compare for UGI Utilities, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3 and 4. The data cover the five-year period 2013-2017. I will highlight the important categories of relative risk, which may be summarized as follows:

Size. In terms of capitalization, UGI Utilities is smaller than the average size of the Gas Group. The S&P Public Utilities is very much larger than all the gas companies that I have considered. 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 UGI Utilities and the Gas Group.

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 UGI Utilities' stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was slightly higher for the Gas Group as compared to the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat higher for the Gas Group as compared to 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 high common equity ratio has low financial risk, while a firm with a low common equity ratio has high financial risk. The five-year average common equity ratios, based on permanent capital based on book value, were 57.4% for UGI Utilities, 53.8% for the Gas Group, and 43.6% for the S&P Public Utilities. The historical common equity ratio for UGI Utilities was

[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).

higher than the Gas Group, although the ratio in this case of 54.80% is clearly with the range of common equity ratios for the Gas Group.

<u>Return on Book Equity</u>. 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 of variation, the greater the degree of variability. During the five-year period, the coefficients of variation were 0.140 (1.8% ÷ 12.9%) for UGI Utilities, 0.076 (0.7% ÷ 9.2%) for the Gas Group, and 0.064 (0.6% ÷ 9.4%) for the S&P Public Utilities. The variability of the Company's rate of return was considerably higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company. And, as I indicated previously, recent changes in the federal income tax law will likely make these variability statistics higher in the future.

<u>Operating Ratios</u>. 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 76.5% for UGI Utilities, 85.1% for the Gas Group, and 79.7% for the S&P Public Utilities. The lower average operating ratio for UGI Utilities suggests somewhat lower risk.

<u>Coverage</u>. 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 AFUDC) was 5.73 times for UGI Utilities, 4.55 times for the Gas Group, and 3.22 times for the S&P Public Utilities. The higher interest coverage

for UGI Utilities suggests slightly lower credit risk. Again, these credit quality indicators will decline prospectively with the implementation of the new lower federal income tax rate.

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 UGI Utilities and the Gas Group. Prospectively, the effective income tax rate will decline and quality of earnings will suffer.

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 80.0% for UGI Utilities, 71.7% for the Gas Group, and 79.5% for the S&P Public Utilities. The Company's levels of IGF have declined in recent years as its construction expenditures have increased. This indicates a changing risk profile for the Company that points to higher risk prospectively. As noted previously, the IGF to construction expenditures will decline with the new lower federal income tax rate.

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. Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market.[3] A comparison of market risk is shown by the Value Line betas of .65 as the average for the Gas Group and .64 for the Subgroup provided on page 2 of Schedule 3 and .64 as the average for the S&P Public Utilities provided on page 3 of Schedule 4.

Q. Please summarize your risk evaluation of UGI Utilities and the Gas Group.

A. The investment risk of UGI Utilities parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size, large throughput to industrial customers, and more variable earned returns, UGI Utilities has somewhat higher risk traits. UGI Utilities has lower risk as shown by its higher common equity ratio, its lower operating ratio and higher interest coverages. The Company's credit quality is comparable to the Gas Group. Its IGF to construction has been trending downward as construction expenditures have increased, which shows more risk prospectively. On balance, the cost of equity for the Gas Group would understate the Company's cost of equity for this case.

RECOMMENDED CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for UGI Utilities 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 UGI Utilities, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated

[3] 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.

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. Since the UGIU Gas does not obtain its capital independently, I have employed the consolidated capital structure ratios of UGI Utilities to calculate the rate of return for this case. The circumstances of UGI Utilities indicate that the capital structure ratios of UGI Utilities should be used for rate of return purposes for both its utility divisions.

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

A. Yes. Schedule 5 presents UGI Utilities' capitalization and related capital structure at September 30, 2018, the end of the historic test year ("HTY"). Also shown on Schedule 5 is the UGI Utilities capital structure estimated at September 30, 2019, the end of the future test year ("FTY"), and at September 30, 2020, the end of the fully projected future test year ("FPFTY"). The changes in UGI Utilities' capital structure consist of: (i) quarterly principal payments of $6.250 million on the variable-rate term-loan in both the FTY and FPFTY (ii) the issuance of two $150 million debt issues in the FTY and FPFTY, and (iii) the Company's projection of retained earnings at the end of the FTY and FPFTY.

Q. Have you made adjustments to the Company's capitalization for ratesetting purposes?

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

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 MLP 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. 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 which will exist during the period of time the proposed rates are to be effective. I will adopt the UGI Utilities' capital structure ratios at the end of the FPFTY of 45.20% long-term debt and 54.80% common equity. These ratios are within the ranges indicated for the Gas Group. 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. In reaching this conclusion, I have analyzed the 12-month average balances of short-term debt for the HTY, 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. In the FPFTY, the CWIP balance exceeds the average amount of short-term debt. Therefore, all short-term debt is removed from the capital structure in the FPFTY.

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 UGI Utilities must be used for developing a fair rate of return for the Company. 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 UGI Utilities 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, 2018. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2019. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the FPFTY. 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 4.73% forecast embedded long-term debt cost rate at September 30, 2020, 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 45.20% long-term debt ratio.

Q. What cost rate have you assigned to the Company's variable-rate debt and the new issues of debt scheduled for the FTY and FPFTY?

A. UGI Utilities entered into an interest rate swap agreement to fix the rate on the variable-rate term-loan. That rate is fixed at 2.988% and will be effective through July 2022. For the new issue of debt in the FTY, I have used a nominal (i.e., coupon) rate of 4.55% for the issue planned on February 28, 2019. The February 2019 issuance reflects the actual interest rate that will be incurred. The interest rate for the issuance in the FPFTY is an estimate that is slightly higher than the known rate from the February 2019 issuance.

<u>COST OF EQUITY – GENERAL APPROACH</u>

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 Utilities, the Gas 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 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 Gas Group and Subgroup and arrived at a cost of equity of 11.25% for UGIU Gas, which includes recognition of strong management performance.

DISCOUNTED CASH FLOW ANALYSIS

Q. Please describe the Discounted Cash Flow 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 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 and assumes 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.[4] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 11.19% for the Gas Group and 11.58% for the Subgroup that was used in the Quarterly Earnings Report.

Among other 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.

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 dividend receipts. It is measured by the dividends 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 November 2018, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend

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

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 November 2018 the average dividend yield was 2.76% for the Gas Group and 2.74% for the Subgroup that was used in the Quarterly Earnings Report, based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six-month period were 2.67% and 2.64%, respectively, for each group. I have used, for the purpose of the DCF model, the six-month average dividend yield of 2.67% for the Gas Group and 2.64% for the Subgroup that was used in the Quarterly Earnings Report. 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 investor 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. This adjustment adds nine to ten basis points to the six-month average historical yield, thus producing the 2.76% adjusted dividend yield for the Gas Group and 2.74% for the Subgroup that was used in the Quarterly Earnings Report.

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 earnings per share growth represents the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of 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 where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the “transition” phase, 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, which are those used by investors when pricing common stocks.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. 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. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner.

Q. How did you determine 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 using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

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

A. I have considered the growth in the financial variables shown on Schedules 8 and 9. In this regard, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks. Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So, with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio. The historical growth rates were taken from the Value Line publication that provides this data. As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance. As shown on Schedule 8, the historical growth of earnings per share was in the range of 0.06% to 2.25% for the Gas Group and -2.00% and 1.25% for the Subgroup that was used in the Quarterly Earnings Report.

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

A. Yes. The constant form of the DCF assumes an infinite stream of cash flows, but 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 investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. 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 the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication suggests that there is no market for this information because investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

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, Reuters, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Reuters, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Reuters, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Reuters, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. 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, Reuters, Zacks, Morningstar, and SNL 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 have also been included on Schedule 9 for the Gas Group and the Subgroup that was used in the Quarterly Earnings Report.

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

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.99% by IBES/First Call, 6.39% by Reuters, 6.22% by Zacks, 7.86% by Morningstar, 5.74% by SNL and 12.17% by Value Line. In each instance, the growth rates are the same or higher for the Subgroup that was used in the Quarterly Earnings Report. There, the growth rates range from 6.29% to 13.92%. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate rather than lower rates of growth in dividends per share and book value per share, thus producing the capital gains yield expected by investors.

Q. What other factors did you consider in developing a growth rate?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). 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 this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[5] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call, Zacks, Morningstar, SNL, and Value Line, represent a reasonable assessment of investor expectations.

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

A. The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 5.74% to 12.17% for the Gas Group and 6.29% to 13.92% for the Subgroup that was used in the Quarterly Earnings Report. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 7.00% is a reasonable estimate of investor expected growth for the Gas Group and is within the array of earnings per share growth rates shown by the analysts' forecasts. Indeed, my 7.00% growth rate is obtained from the analysts' growth forecasts that cover a five-year period, which are the growth rates that investors employ for

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

DCF purposes. For the Subgroup that was used in the Quarterly Earnings Report, a higher 7.25% is indicated from the data presented on Schedule 9. Improved economic growth and continued gas utility infrastructure spending argues for a DCF growth rate near the high end of the range. Economic growth has picked up with the implementation of the new federal corporate income tax provisions.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 30.96% long-term debt, 0.00% preferred stock, and 69.04% 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. Where a firm's capitalization as measured by its stock price diverges from its book value capitalization, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value. A leverage adjustment accounts for this difference 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 than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the rate setting 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 rate setting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the 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," provides a return of 8.35% 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 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 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 indeed 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 that 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. The adjustment that I label as 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), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to 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 8.35%, which is the return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) plus 2.84% compensation for having a 47.30% debt ratio, plus 0.00% for having a 0.00% preferred stock ratio. The sum of the parts is 11.19% (8.35% + 2.84% + 0.00%) 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 summed the 2.76% dividend yield, the 7.00% growth rate, and the 1.43% for the leverage adjustment in order to arrive at the same 11.19% (2.76% + 7.00% + 1.43%) return. I know of no means to mathematically solve for the 1.43% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 1.43% adjustment is merely a convenient way to compare the 11.19% return computed directly with the Modigliani & Miller formulas to the 9.76% return generated by the DCF model (i.e., D_1/P_0 + g, or the traditional form of the DCF -- see page 1 of Schedule 7) based on a market value capital structure. A 9.76% 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. I have applied the same process to the Subgroup that was used in the Quarterly Earnings Report and established a 1.59% leverage adjustment for that group.

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 ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	$lev.$	=	k
Gas Group	2.76%	+	7.00%	+	1.43%	=	11.19%
Subgroup	2.74%	+	7.25%	+	1.59%	=	11.58%

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 price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results 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 page 2 of Schedule 1. That result is 11.50%.

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 5.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is 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 page 1 of Schedule 11. For the twelve months ended November 2018, the average monthly yield on Moody's index of A-rated public utility bonds was 4.20%. For the six and three-month periods ended November 2018, the yields were 4.35% and 4.43%, respectively. During the twelve-months ended November 2018, the range of the yields on A-rated public utility bonds was 3.79% to 4.52%. 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 1.12% on a twelve-month average basis, 1.19% on a six-month average basis, and 1.15% on a three-month average basis. From these averages, 1.25% represents a reasonable 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. The 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 December 1, 2018, and a yield spread of 1.25%, 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:

		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2018	Fourth	4.2%	5.1%	3.4%	1.25%	4.65%
2019	First	4.5%	5.3%	3.5%	1.25%	4.75%
2019	Second	4.6%	5.5%	3.6%	1.25%	4.85%
2019	Third	4.7%	5.5%	3.6%	1.25%	4.85%
2019	Fourth	4.8%	5.6%	3.7%	1.25%	4.95%
2020	First	4.8%	5.6%	3.7%	1.25%	4.95%

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 December 1, 2018 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
2020-2024	5.0%	5.9%	3.9%
2025-2029	5.1%	6.0%	4.2%

The longer-term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near-term forecasts. By focusing more on these forecasts, a 5.00% yield on A-rated public utility bonds represents a reasonable benchmark for measuring the cost of equity in this case. In reaching my conclusion as to a prospective yield on A-rated public utility debt, I have considered the data relied upon by investors.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2017 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 page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	7.08%
Average Across All Interest Rates	5.64%
High Interest Rates	4.18%

Based on my analysis of the historical data, the equity risk premium was 7.08% when the marginal cost of long-term government bonds was low (i.e., 2.96%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.22% on average during periods of high interest rates) the spread narrowed to 4.18%. Over the entire spectrum of interest rates, the equity risk premium was 5.64% when the average government bond yield was 5.07%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.08% premium related to periods of low interest rates and the 5.64% premium related to average interest rates across all levels.

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:

	i	+	*RP*	=	*k*
Gas Group and Subgroup	5.00%	+	6.50%	=	11.50%

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 11.98% for the Gas Group and 12.07% for the Subgroup that was used in the Quarterly Earnings Report. 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 0.65 for the Gas Group and 0.64 for the Subgroup that was used in the Quarterly Earnings Report.

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 betas must be reflective of the financial risk associated with the rate setting 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. 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,[6] as follows:

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

where 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 0.48 for the Gas 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 0.82 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.83 for the Subgroup that was used in the Quarterly Earnings Report.

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 November 2018, the average yield on 30-year Treasury bonds was 3.09%. For the six- and three-months

[6] 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, December 27-29, 1971. (May 1972), pp. 435-452.

ended November 2018, the yields on 30-year Treasury bonds were 3.16% and 3.28%, respectively. During the twelve-months ended November 2018, the range of the yields on 30-year Treasury bonds was 2.77% to 3.36%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). As noted previously, low interest rates were the product of the policy of the Federal Open Market Committee ("FOMC") in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC ended its bond purchasing program at its policy meeting on October 29, 2014. At its December 16, 2015 meeting, the FOMC increased the federal funds rate range by 0.25 percentage points. On December 14, 2016, the FOMC acted again by raising the federal funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increases in interest rates. In addition, the Fed has indicated that it will reduce the size of its balance sheet. FOMC increased the federal funds rate on three occasions in 2017 (i.e., March 15, 2017, June 14, 2017 and December 13, 2017) by one-quarter percentage point each. At its policy meetings on March 21, 2018, June 13, 2018, September 26, 2018, and December 19, 2018, the FOMC acted again to increase the federal funds rate by one-quarter percentage point in each instance. There have been nine (9) one-quarter percentage point increases in the Fed Funds rate since the FOMC began to normalize interest rates following the financial crisis and the Great Recession. Additional increases may be expected depending upon the rate of increase in price levels. This buttresses the prospect that higher interest rates are on the horizon.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on December 1, 2018 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.4% to 3.7% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 3.9% from 2020 through 2024 and 4.2% from 2025 to 2029. 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 3.75% risk-free rate of return for CAPM purposes, which considers the Blue Chip forecasts.

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

A. As shown in the lower panel of data presented on page 2 of Schedule 13, 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 page 1 of Schedule 12. On that schedule, the market return was 11.97% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 2.96% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 11.96% (11.97% + 11.95% = 23.92% ÷ 2) and the average yield on long-term government bonds of 4.02% (2.96% + 5.07% = 8.03% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 7.94% (11.96% - 4.02%) based on historical data, as shown on page 2 of Schedule 13. As also shown on page 2 of Schedule 13, I calculated the forecast returns, which show an 13.78% total market return from the Value Line data and a DCF return of 13.00% for the S&P 500. With the average forecast return of 13.39% (13.78% + 13.00% = 26.78% ÷ 2), I calculated a market premium of 9.64% (13.39% - 3.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 8.79% (9.64% + 7.94% = 17.58% ÷ 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 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"; The Journal of Finance, 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 understate the cost of equity significantly 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. In this regard, the Gas Group has a market-based average equity capitalization of $4,209 million. For my CAPM analysis, I have adopted a mid-cap adjustment of 1.02%, as shown on page 3 of Schedule 13.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.84 for the Gas Group, the 8.56% market premium, and the 1.02% size adjustment, the following result is indicated.

	Rf	***+***	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	***=***	***k***
Gas Group	3.75%	+	0.82	x (	8.79%	) +	1.02%	=	11.98%
Subgroup	3.75%	+	0.83	x (	8.79%	) +	1.02%	=	12.07%

<u>COMPARABLE EARNINGS APPROACH</u>

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 risks 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 vs. 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 Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas 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 page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon 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 page 2 of Schedule 14, 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 11.7% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 13.8% also using values less than 20%, as provided on page 2 of Schedule 14. Using the average of these data my Comparable Earnings result is 12.75%, as shown on page 2 of Schedule 1.

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 11.25% for UGIU Gas, which includes 25 basis points or 0.25% 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 greater risk characteristics relative to the barometer group companies, as well as the general condition of the capital markets. 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 11.25% 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 the TCJA, 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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-one 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.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

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 GAS STATEMENT NO. 6 – PAUL R. HERBERT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
Paul R. Herbert

Topics Addressed: **Cost of Service Allocation**

Date: January 28, 2019

Q. Please state your name and business address.

A. My name is Paul R. Herbert. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. By whom are you employed?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC.

Q. Please describe your position with Gannett Fleming Valuation and Rate Consultants, LLC, and briefly state your general duties and responsibilities.

A. I am a Senior Consultant. My duties and responsibilities include the preparation of accounting and financial data for revenue requirements, the allocation of cost of service to customer classifications, and the design of customer rates in support of public utility rate filings.

Q. Have you presented testimony in rate proceedings before a regulatory agency?

A. Yes. I have testified before the Pennsylvania Public Utility Commission, the New Jersey Board of Public Utilities, the Public Utilities Commission of Ohio, the Public Service Commission of West Virginia, the Kentucky Public Service Commission, the Iowa State Utilities Board, the Virginia State Corporation Commission, the Illinois Commerce Commission, the Tennessee Regulatory Authority, the California Public Utilities Commission, New Mexico Public Regulation Commission, the Delaware Public Service Commission, Arizona Corporate Commission, the Connecticut Department of Public Utility Control, the Idaho Public Utilities Commission, the Hawaii Public Utilities Commission, the New York State Public Service Commission, and the Missouri Public Service Commission concerning revenue requirements, cost of service allocation, rate design and cash working capital claims. A list of the cases in which I have testified is provided at the end of my direct testimony.

Q. What is your educational background?

A. I have a Bachelor of Science Degree in Finance from the Pennsylvania State University, University Park, Pennsylvania.

Q. Would you please describe your professional affiliations?

A. I am a member of the American Water Works Association and serve as a member of the Management Committee for the Pennsylvania Section. I am also a member of the Pennsylvania Municipal Authorities Association. In 1998, I became a member of the National Association of Water Companies as well as a member of its Rates and Revenue Committee.

Q. Briefly describe your work experience.

A. I joined the Valuation Division of Gannett Fleming Corddry and Carpenter, Inc., predecessor to Gannett Fleming Valuation and Rate Consultants, LLC, in September 1977, as a Junior Rate Analyst. Since then, I have advanced through several positions and was assigned the position of Manager of Rate Studies on July 1, 1990. On June 1, 1994, I was promoted to Vice President and on November 1, 2003, I was promoted to Senior Vice President. On July 1, 2007, I was promoted to the position as President and served in that capacity until December 31, 2018. My current position is Senior Consultant.

While attending Penn State, I was employed during the summers of 1972, 1973 and 1974 by the United Telephone System - Eastern Group in its accounting department. Upon graduation from college in 1975, I was employed by Herbert Associates, Inc., Consulting Engineers (now Herbert Rowland and Grubic, Inc.), as a field office manager until September 1977.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I will explain the cost of service allocation study

<u>COST OF SERVICE ALLOCATION STUDY</u>

Q. What is the purpose of the cost of service allocation study?

A. The purpose of the study is to allocate the total cost of service to the appropriate service classifications.

Q. Have you prepared cost of service studies for UGI Gas in prior cases?

A. Yes. I prepared the cost of service study in the UGI Penn Natural Gas, Inc. (now the UGI North Rate District) rate cases at Docket Nos. R-2016-2580030 and R-2008-2079660 and the UGI Central Penn Gas, Inc. (now the UGI Central Rate District) rate case at Docket No. R-2010-2214415. I also prepared the cost of service study for UGI Utilities, Inc. - Gas Division (now the UGI South Rate District) rate case at Docket No. R-2015-2518438.

Q. What method of cost allocation was used in the studies?

A. I used the Average and Extra Demand Method (Average/Excess), which is described in UGI Gas Exhibit D and in the text, "Gas Rate Fundamentals", published by the American Gas Association's Rate Committee.

Q. Please describe UGI Gas Exhibit D.

A. UGI Gas Exhibit D titled, "Cost of Service Allocation Study as of September 30, 2020," is the cost of service allocation study prepared for UGI Gas in support of its claims in this proceeding. It sets forth the results of the study based on the projected costs and conditions for the fully projected future test year for the twelve months ending September 30, 2020 ("FPFTY"). The data in the exhibit include a description of the methods and procedures used in the study, the allocations of cost of service and measure of value, the factors on which the allocations were based and an analysis of customer costs.

Q. Please outline the procedure that you followed in the first cost allocation study.

A. The detailed allocation of costs to cost functions and service classifications is presented in Schedule E, pages 10 through 13, of UGI Gas Exhibit D. Gas costs are excluded from the amounts in Schedule E in order to develop costs by function and classification related to the delivery of gas.

In the detailed allocation, the items of cost, which include operating expenses, depreciation expense, taxes, and income available for return, are identified in column 1 of Schedule E. The cost of each item, shown in column 3, is allocated to the appropriate service classifications: Residential (R and RT), Non-Residential (N and

NT), Delivery Service (DS), Large Firm Delivery Service (LFD), Extended Large Firm Delivery Service (XD-Firm), and Interruptible Service (IS).

The allocation factor codes entered in column 2 enable one to determine the specific basis for the allocation of each item. The factor codes refer to the information presented in Schedule F, beginning on page 14, of the exhibit.

Q. Please explain the allocation of some of the large cost items in the study.

A. Referring to some of the larger delivery cost items, the costs associated with natural gas production expenses were allocated based on purchased gas cost ("PGC") volumes for Rate R and Rate N customers.

The costs related to distribution mains were first directly assigned to Rate XD-Firm and XD-I (a portion of IS-interruptible) customers based on an analysis of the mains and the proportion thereof serving each individual Rate XD customer. The methods and procedures used to determine the portion of mains directly assigned to Rate XD customers were provided by Company personnel. The remaining cost of mains was separated into small mains (2-inch and smaller) and large mains (over 2-inch). This was initially done so that an adjustment for certain large Rate LFD and large Rate IS customers not connected to small mains could be excluded from the small mains allocation. However, no specific information to determine the size of main that each Rate LFD or Rate IS customer is connected was readily available. Therefore, the allocation of small and large distribution mains is the same; they are allocated to the Rate R, N, DS, and LFD classes based on the average and extra capacity demand for each classification, and only the average day demand for the Interruptible (IS) class (excluding the XD-I customers).

Customers under Rate XD-Firm and XD-I were excluded from the allocation of small and large distribution mains since Rate XD customers were directly assigned the cost of mains serving them, as explained above. Interruptible volumes were removed from the extra capacity calculations as these volumes can be curtailed during periods of peak demand.

Costs related to service lines in Account 380 were allocated to classes, based on an analysis of service line investment by size and Rate Class as presented in the response the Standard Data Request SDR-COS-6. Costs related to meters in Accounts 381 and 385 were allocated to the classes based on an analysis of meter investment by size and Rate Class as presented in response to Standard Data Request SDR-COS-7.

Q. Please explain the allocation of uncollectible accounts and customer assistance expenses.

A. Uncollectible accounts associated with the gas cost portion are allocated consistent with the recovery of such costs through the Merchant Function Charge (Rider D). The remaining uncollectible account cost is recovered based on an analysis of write-offs. Costs associated with customer assistance programs are allocated directly to the residential class.

Q. Please describe the allocation of customer accounting costs and the remaining cost of service elements.

A. Customer accounting costs were allocated to service classifications on the basis of the number of customers. Administrative and general costs were allocated on the basis of the allocated direct operation and maintenance costs, excluding gas production expenses.

Annual depreciation accruals were allocated on the basis of the function of the facilities represented by the depreciation expense for each depreciable plant account. Similarly, certain taxes other than income taxes, income taxes, and income available for return were allocated on the basis of allocated rate base, including the original cost less accrued depreciation of utility plant in service and other rate base elements.

Q. What are the results of the cost of service allocation study?

A. The results of the cost of service allocation set forth in Schedule E are brought forward and summarized in Schedule D. The total cost of service by classification in Schedule D is then brought forward to Schedule A (without gas costs), columns 2 and 3, where these results are compared to the *pro forma* revenues under present rates (columns 4 and 5) and proposed rates (columns 6 and 7). The proposed change in revenue under proposed rates and the percent change are shown in columns 8 and 9 of Schedule A. Please refer to the direct testimony of Paul J. Szykman (UGI Gas St. No. 1) and the direct testimony David E. Lahoff (UGI Gas St. No. 8) for an explanation of the proposed rate design and revenue distribution.

Q. Did you prepare a schedule showing the rate of return by classification?

A. Yes. Schedule B sets forth the rate of return by classification under present rates, and Schedule C shows the rate of return by classification under proposed rates.

Q. Did you prepare an analysis of customer costs?

A. Yes. I prepared a fully allocated customer cost analysis and a direct customer cost analysis. Both analyses of customer costs are presented in Schedule G of UGI Gas Exhibit D.

Q. Please explain the analysis of customer costs as set forth in UGI Gas Exhibit D.

A. The customer costs were determined by allocating the cost of service to cost functions and to service classifications. The volumetric and customer functional costs were determined by an allocation of the total cost of service to these functions in Schedule E of UGI Gas Exhibit D. The customer costs were further allocated to the R, N, DS, LFD, XD, and Interruptible Service classifications in the same schedule. The factors that were the bases for the allocation to cost functions and the allocation of customer costs to classifications are presented in Schedule F. A summary of the customer costs and the development of the costs per customer per month are presented in Schedule G.

Q. Did you prepare an analysis of costs related to the demand charge for Rate LFD and Rate XD-Firm Service?

A. Yes. The analysis of costs related to the demand charges for Rate LFD and Rate XD Service is presented in Schedule H of UGI Gas Exhibit D.

Q. Please explain the analysis of the Rate LFD and Rate XD Service costs related to demand charges as set forth in UGI Gas Exhibit D.

A. The costs related to Rate LFD and Rate XD Service demand charges were determined by the allocation of certain fixed costs, depreciation, taxes and return to these classifications. The allocation was performed in Schedule E. A summary of the allocated costs and the development of the unit demand costs are presented in Schedule H.

Q. Please describe the cost of service studies by district in UGI Gas Exhibit H.

A. Pursuant to the settlement in the merger case, cost of service studies for each of the rate districts (*i.e.*, South, North and Central) are presented in Book XIII, Exhibit H. The cost of service studies by Rate District employ the same methodology, procedures and schedules as the UGI Gas Division (Combined) study presented in Exhibit D.

Q. Does that conclude your direct testimony?

A. Yes, it does.

PAUL R. HERBERT – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
1.	1983	Pa. PUC	R-832399	T. W. Phillips Gas and Oil Co.	Pro Forma Revenues
2.	1989	Pa. PUC	R-891208	Pennsylvania-American Water Company	Bill Analysis and Rate Application
3.	1991	WV PSC	91-106-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42)
4.	1992	Pa. PUC	R-922276	North Penn Gas Company	Cash Working Capital
5.	1992	NJ BPU	WR92050532J	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
6.	1994	Pa. PUC	R-943053	The York Water Company	Cost Allocation and Rate Design
7.	1994	Pa. PUC	R-943124	City of Bethlehem	Revenue Requirements, Cost Allocation, Rate Design and Cash Working Capital
8.	1994	Pa. PUC	R-943177	Roaring Creek Water Company	Cash Working Capital
9.	1994	Pa. PUC	R-943245	North Penn Gas Company	Cash Working Capital
10.	1994	NJ BPU	WR94070325	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
11.	1995	Pa. PUC	R-953300	Citizens Utilities Water Company of Pennsylvania	Cost Allocation and Rate Design
12.	1995	Pa. PUC	R-953378	Apollo Gas Company	Rev. Requirements and Rate Design
13.	1995	Pa. PUC	R-953379	Carnegie Natural Gas Company	Rev. Requirements and Rate Design
14.	1996	Pa. PUC	R-963619	The York Water Company	Cost Allocation and Rate Design
15.	1997	Pa. PUC	R-973972	Consumers Pennsylvania Water Company Shenango Valley Division	Cash Working Capital
16.	1998	Ohio PUC	98-178-WS-AIR	Citizens Utilities Company of Ohio	Water and Wastewater Cost Allocation and Rate Design
17.	1998	Pa. PUC	R-984375	City of Bethlehem - Bureau of Water	Revenue Requirement, Cost Allocation and Rate Design
18.	1999	Pa. PUC	R-994605	The York Water Company	Cost Allocation and Rate Design
19.	1999	Pa. PUC	R-994868	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
20.	1999	WV PSC	99-1570-W-MA	Clarksburg Water Board	Revenue Requirements (Rule 42), Cost Allocation and Rate Design
21.	2000	Ky. PSC	2000-120	Kentucky-American Water Company	Cost Allocation and Rate Design
22.	2000	Pa. PUC	R-00005277	PPL Gas Utilities	Cash Working Capital
23.	2000	NJ BPU	WR00080575	Atlantic City Sewerage Company	Cost Allocation and Rate Design
24.	2001	Ia. St Util Bd	RPU-01-4	Iowa-American Water Company	Cost Allocation and Rate Design
25.	2001	Va. St. CC	PUE010312	Virginia-American Water Company	Cost Allocation and Rate Design
26.	2001	WV PSC	01-0326-W-42T	West-Virginia American Water Company	Cost Allocation And Rate Design
27.	2001	Pa. PUC	R-016114	City of Lancaster	Tapping Fee Study
28.	2001	Pa. PUC	R-016236	The York Water Company	Cost Allocation and Rate Design
29.	2001	Pa. PUC	R-016339	Pennsylvania-American Water Company	Cost Allocation and Rate Design
30.	2001	Pa. PUC	R-016750	Philadelphia Suburban Water Company	Cost Allocation and Rate Design
31.	2002	Va.St.CC	PUE-2002-0375	Virginia-American Water Company	Cost Allocation and Rate Design
32.	2003	Pa. PUC	R-027975	The York Water Company	Cost Allocation and Rate Design
33.	2003	Tn Reg Auth	03-	Tennessee-American Water Company	Cost Allocation and Rate Design
34.	2003	Pa. PUC	R-038304	Pennsylvania-American Water Company	Cost Allocation and Rate Design
35.	2003	NJ BPU	WR03070511	New Jersey-American Water Company	Cost Allocation and Rate Design
36.	2003	Mo. PSC	WR-2003-0500	Missouri-American Water Company	Cost Allocation and Rate Design
37.	2004	Va.St.CC	PUE-200 -	Virginia-American Water Company	Cost Allocation and Rate Design
38.	2004	Pa. PUC	R-038805	Pennsylvania Suburban Water Company	Cost Allocation and Rate Design
39.	2004	Pa. PUC	R-049165	The York Water Company	Cost Allocation and Rate Design
40.	2004	NJ BPU	WRO4091064	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
41.	2005	WV PSC	04-1024-S-MA	Morgantown Utility Board	Cost Allocation and Rate Design
42.	2005	WV PSC	04-1025-W-MA	Morgantown Utility Board	Cost Allocation and Rate Design
43.	2005	Pa. PUC	R-051030	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
44.	2006	Pa. PUC	R-051178	T. W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
45.	2006	Pa. PUC	R-061322	The York Water Company	Cost Allocation and Rate Design
46.	2006	NJ BPU	WR-06030257	New Jersey American Water Company	Cost Allocation and Rate Design
47.	2006	Pa. PUC	R-061398	PPL Gas Utilities, Inc.	Cost Allocation and Rate Design
48.	2006	NM PRC	06-00208-UT	New Mexico American Water Company	Cost Allocation and Rate Design
49.	2006	Tn Reg Auth	06-00290	Tennessee American Water Company	Cost Allocation and Rate Design
50.	2007	Ca. PUC	U-339-W	Suburban Water Systems	Water Conservation Rate Design
51.	2007	Ca. PUC	U-168-W	San Jose Water Company	Water Conservation Rate Design
52.	2007	Pa. PUC	R-00072229	Pennsylvania American Water Company	Cost Allocation and Rate Design
53.	2007	Ky. PSC	2007-00143	Kentucky American Water Company	Cost Allocation and Rate Design
54.	2007	Mo. PSC	WR-2007-0216	Missouri American Water Company	Cost Allocation and Rate Design

PAUL R. HERBERT – LIST OF CASES TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
55.	2007	Oh. PUC	07-1112-WS-IR	Ohio American Water Company	Cost Allocation and Rate Design
56.	2007	Il. CC	07-0507	Illinois American Water Company	Customer Class Demand Study
57.	2007	Pa. PUC	R-00072711	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
58.	2007	NJ BPU	WR07110866	The Atlantic City Sewerage Company	Cost Allocation and Rate Design
59.	2007	Pa. PUC	R-00072492	City of Bethlehem – Bureau of Water	Revenue Reqmts, Cost Alloc.
60.	2007	WV PSC	07-0541-W-MA	Clarksburg Water Board	Cost Allocation and Rate Design
61.	2007	WV PSC	07-0998-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
62.	2008	NJ BPU	WR08010020	New Jersey American Water Company	Cost Allocation and Rate Design
63.	2008	Va St CC	PUE-2008-0009	Virginia American Water Company	Cost Allocation and Rate Design
64.	2008	Tn.Reg.Auth.	08-00039	Tennessee American Water Company	Cost Allocation and Rate Design
65.	2008	Mo PSC	WR-2008-0311	Missouri American Water Company	Cost Allocation and Rate Design
66.	2008	De PSC	08-96	Artesian Water Company, Inc.	Cost Allocation and Rate Design
67.	2008	Pa PUC	R-2008-2032689	Penna. American Water Co. – Coatesville Wastewater	Cost Allocation and Rate Design
68.	2008	AZ CC.	W-01303A-08-0227 SW-01303A-08-0227	Arizona American Water Co. – Water - Wastewater	Cost Allocation and Rate Design
69.	2008	Pa PUC	R-2008-2023067	The York Water Company	Cost Allocation and Rate Design
70.	2008	WV PSC	08-0900-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
71.	2008	Ky PSC	2008-00250	Frankfort Electric and Water Plant Board	Cost Allocation and Rate Design
72.	2008	Ky PSC	2008-00427	Kentucky American Water Company	Cost Allocation and Rate Design
73.	2009	Pa PUC	2008-2079660	UGI – Penn Natural Gas	Cost of Service Allocation
74.	2009	Pa PUC	2008-2079675	UGI – Central Penn Gas	Cost of Service Allocation
75.	2009	Pa PUC	2009-2097323	Pennsylvania American Water Co.	Cost Allocation and Rate Design
76.	2009	Ia St Util Bd	RPU-09-	Iowa-American Water Company	Cost Allocation and Rate Design
77.	2009	Il CC	09-0319	Illinois-American Water Company	Cost Allocation and Rate Design
78.	2009	Oh PUC	09-391-WS-AIR	Ohio-American Water Company	Cost Allocation and Rate Design
79.	2009	Pa PUC	R-2009-2132019	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
80.	2009	Va St CC	PUE-2009-0059	Aqua Virginia, Inc.	Cost Allocation (only)
81.	2009	Mo PSC	WR-2010-0131	Missouri American Water Company	Cost Allocation and Rate Design
82.	2010	VaSt CorpCom	PUE-2010-00001	Virginia American Water Company	Cost Allocation and Rate Design
83.	2010	Ky PSC	2010-00036	Kentucky American Water Company	Cost Allocation and Rate Design
84.	2010	NJ BPU	WR10040260	New Jersey American Water Company	Cost Allocation and Rate Design
85.	2010	Pa PUC	2010-2167797	T.W. Phillips Gas and Oil Co.	Cost Allocation and Rate Design
86.	2010	Pa PUC	2010-2166212	Pennsylvania American Water Co. - Wastewater	Cost Allocation and Rate Design
87.	2010	Pa PUC	R-2010-2157140	The York Water Company	Cost Allocation and Rate Design
88.	2010	Ky PSC	2010-00094	Northern Kentucky Water District	Cost Allocation and Rate Design
89.	2010	WV PSC	10-0920-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
90.	2010	Tn Reg Auth	10-00189	Tennessee American Water Company	Cost Allocation and Rate Design
91.	2010	Ct PU RgAth	10-09-08	United Water Connecticut	Cost Allocation and Rate Design
92.	2010	Pa PUC	R-2010-2179103	City of Lancaster-Bureau of Water	Rev Rqmts, Cst Alloc/Rate Design
93.	2011	Pa PUC	R-2010-2214415	UGI Central Penn Gas, Inc.	Cost Allocation
94.	2011	Pa PUC	R-2011-2232359	The Newtown Artesian Water Co.	Revenue Requirement
95.	2011	Pa PUC	R-2011-2232243	Pennsylvania-American Water Co.	Cost Allocation and Rate Design
96.	2011	Pa PUC	R-2011-2232985	United Water Pennsylvania Inc.	Demand Study, COS/Rate Design
97.	2011	Pa PUC	R-2011-2244756	City of Bethlehem-Bureau of Water	Rev. Rqmts/COS/Rate Design
98.	2011	Mo PSC	WR-2011-0337-338	Missouri American Water Company	Cost Allocation and Rate Design
99.	2011	Oh PUC	11-4161-WS-AIR	Ohio American Water Company	Cost Allocation and Rate Design
100.	2011	NJ BPU	WR11070460	New Jersey American Water Company	Cost Allocation and Rate Design
101.	2011	Id PUC	UWI-W-11-02	United Water Idaho Inc.	Cost Allocation and Rate Design
102	2011	Il CC	11-0767	Illinois-American Water Company	Cost Allocation and Rate Design
103.	2011	Pa PUC	R-2011-2267958	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
104.	2011	VaStCom	2011-00099	Aqua Virginia, Inc.	Cost Allocation
105.	2011	VaStCom	2011-00127	Virginia American Water Company	Cost Allocation and Rate Design
106.	2012	TnRegAuth	12-00049	Tennessee American Water Company	Cost Allocation and Rate Design
107.	2012	Ky PSC	2012-00072	Northern Kentucky Water District	Cost Allocation and Rate Design
108.	2012	Pa PUC	R-2012-2310366	Lancaster, City of – Sewer Fund	Cost Allocation and Rate Design
109.	2012	Ky PSC	2012-00520	Kentucky American Water Co.	Cost Allocation and Rate Design
110.	2013	WV PSC	12-1649-W-42T	West Virginia American Water Co.	Cost Allocation and Rate Design
111.	2013	Ia St Util Bd	RPU-2013-000_	Iowa American Water Company	Cost Allocation and Rate Design
112.	2013	Pa PUC	R-2013-2355276	Pennsylvania American Water Co.	Cost Allocation and Rate Design

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
113.	2013	Pa PUC	R-2012-2336379	The York Water Company	Cost Allocation and Rate Design
114.	2013	Pa PUC	R-2013-2350509	City of DuBois – Bureau of Water	Cost Allocation and Rate Design
115.	2013	Pa PUC	R-2013-2390244	City of Bethlehem – Bureau of Water	Cost Allocation and Rate Design
116.	2014	Pa PUC	R-2014-2418872	City of Lancaster – Bureau of Water	Cost Allocation and Rate Design
117.	2014	Pa PUC	R-2014-2428304	Borough of Hanover	Cost Allocation and Rate Design
118.	2014	VAStCom	2014-00045	Aqua Virginia, Inc.	Cost Allocation
119.	2015	NJ BPU	WR15010035	New Jersey American Water Company	Cost Allocation and Rate Design
120.	2015	Pa PUC	R-2015-2462723	United Water PA	Cost Allocation and Rate Design
121.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Cost Allocation and Rate Design
122.	2015	Id PUC	UWI-W-15-01	United Water Idaho Inc.	Pro Forma Revenues
123.	2015	Mo PSC	WR-2015-0301	Missouri American Water Company	Cost Allocation and Rate Design
124.	2015	Va St Com	PUE-2015-00097	Virginia American Water Company	Cost Allocation and Rate Design
125.	2015	Hi PSC	2015-0350	HOH Utilities, Inc.	Cost Allocation and Rate Design
126.	2016	Ky PSC	2015-00418	Kentucky American Water Company	Cost Allocation and Rate Design
127.	2016	Pa PUC	R-2015-2518438	UGI Utilities, Inc. - Gas Division	Cost Allocation
128.	2016	Il CC	16-0093	Illinois American Water Company	Cost Alloc/Rate Dsgn/Demand Sty
129.	2016	NY PSC	16-W-0130	SUEZ Water New York Inc.	Cost Allocation and Rate Design
130.	2016	Oh PUC	16-0907-WW-AIR	Aqua Ohio, Inc.	Cost Allocation and Rate Design
131.	2016	Ia St Util Bd	RPU-2016-0002	Iowa American Water Company	Cost Allocation and Rate Design
132.	2016	NJ BPU	WR16100957	Atlantic City Sewerage Company	Cost Allocation and Rate Design
133.	2017	Pa PUC	R-2016-2580030	UGI Penn Natural Gas, Inc.	Cost Allocation and Rate Design
134.	2017	Pa PUC	R-2017-2595853	Pennsylvania American Water Co.	Cost Allocation and Rate Design
135.	2017	IL CC	17-0259	Aqua Illinois, Inc.	Cost Allocation and Rate Design
136.	2017	NY PSC	17-W-0528	SUEZ Water Owego-Nichols, Inc.	Cost Allocation and Rate Design
137.	2017	NJ BPU	WR17090985	New Jersey American Water Company	Cost Allocation and Rate Design
138.	2017	Ca PUC	A.18-01-004	San Jose Water Company	Rate Design
139.	2018	PaPUC	R-2018-3000834	SUEZ Water Pennsylvania Inc.	Cost Allocation and Rate Design
140.	2018	PaPUC	R-2018-3000019	The York Water Company	Cost Allocation and Rate Design
141.	2018	NJ BPU	WR18050593	SUEZ Water New Jersey, Inc.	Cost Allocation and Rate Design
142.	2018	Pa PUC	R-2018-3001306	Hidden Valley Utility Services, L.P. – Water	Revenue Requirements
143.	2018	Pa PUC	R-2018-3001307	Hidden Valley Utility Services, L.P. - Wastewater	Revenue Requirements
144.	2018	Pa PUC	R-2018-3003558	Aqua Pennsylvania, Inc.	Cost Allocation and Rate Design
145.	2018	Pa PUC	R-2018-3003566	Aqua Pennsylvania Wastewater, Inc.	Cost Allocation and Rate Design

UGI GAS STATEMENT NO. 7 – JOHN F. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2018-3006814

UGI Utilities, Inc. – Gas Division

Statement No. 7

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

Topics Addressed: Depreciation

Date: January 28, 2019

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2018-3006814

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 a BA degree in Engineering 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 32 years of depreciation experience, which includes expert testimony in numerous cases before 13 regulatory commissions, including this 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 my present position as 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. I assisted in the preparation of depreciation studies for the following telephone companies: Alberta Government Telephone, Commonwealth Telephone Company, Telus, United Telephone Company of New Jersey and United Telephone of Pennsylvania. I assisted in the preparation of depreciation studies for the following companies in the railroad industry: CSX Transportation, Union Pacific Railroad, Burlington Northern Railroad, Burlington Northern Santa Fe Railway, Amtrak, Kansas City Southern Railroad, Norfolk & Western, Southern Railway, and Norfolk Southern Corporation.

I assisted in the preparation of depreciation studies for the following organizations in the electric industry: AmerenUE, Arizona Public Service Company, UGI Utilities, Inc. - Electric Division, Penelec, Metropolitan Edison, the City of Red Deer, Nova Scotia Power, Newfoundland Power, Owen Electric Cooperative, Bangor Hydro Electric Company, Maine Public Service Company, Michigan Electric Transmission Company, PECO, Jackson Electric Cooperative Corporation, Houston Lighting and Power, TXU, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, and the City of Calgary - Electric System.

I assisted in the preparation of depreciation studies for the following gas companies: BGE, PECO, UGI Utilities, Inc., North Penn Gas, PFG Gas, UGI Central Penn Gas, Inc., Equitable Gas, Centra Gas Alberta, Questar Gas, Orange and Rockland, Con Edison, Dominion East Ohio, AmerenUE, AmerenCILCO, AmerenCIPS, and AmerenIP.

In each of the above studies, 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 Connecticut Public Utilities Regulatory Authority and the Pennsylvania Public Utility Commission.

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 2000, 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 Imbalances and True-Up" and "Data Requirements for a Depreciation Study."

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 consolidated Pennsylvania gas plant of UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company"). I have been retained by the Company as a depreciation consultant. UGI Gas retained me to determine the book depreciation reserve as of September 30, 2020, 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.

The Company is proceeding with a consolidated base rate case filing for its gas operations in Pennsylvania related to its customers served by the three rate districts of the now consolidated UGI Gas, which service territories are comprised of UGI South (the former Gas Division of UGI Utilities, Inc.), UGI Central (the former UGI Central Penn Gas, Inc., or "UGI CPG"), and UGI North (the former UGI Penn Natural Gas, Inc., or "UGI PNG"). Effective October 1, 2018, UGI Utilities, Inc., UGI CPG, and UGI PNG merged and the regulated gas operations became the Gas Division of UGI Utilities, Inc.

I am also a sponsoring witness for UGI Gas's depreciated original cost of gas 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, 2020.

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 Gas Exhibit I:

Item No.	Subject
I-A-3	Description of Depreciation Methods and Factors Considered in Arriving at Estimates of Service Life and Dispersion by Account
I-A-4	Survivor Curves and Surviving Original Cost Including Related Annual and Accrued Depreciation
I-A-5	Comparison of Calculated Reserve vs. Book Reserve
I-A-6	Survivor Curves and Annual Accrual Rates
I-A-7	Cumulative Depreciated Original Cost by Vintage Year
l-A-17	Net Salvage

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

A. Yes. I provided testimony on depreciation matters for the Company in the prior two UGI PNG base rate cases at Docket No. R-2016-2580030 and Docket No. R-2008-2079660, the prior two UGI CPG base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the recent base rate case for UGI Utilities, Inc. – Gas Division at Docket No. R-2015-2518438. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's base rate case filed in 1995 at Docket No. R-00953297.

III. <u>OUTLINE OF EXHIBITS C (FULLY PROJECTED), C (FUTURE) AND C (HISTORIC)</u>

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

A. Yes, I am attaching and sponsoring the following exhibits: UGI Gas Exhibit C (Fully Projected), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Historic). UGI Gas Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2020 ("FPFTY") for the consolidated gas company, *i.e.*, the former UGI Gas (now UGI South), as well as the two former subsidiaries, *i.e.*, UGI PNG (now UGI North) and UGI CPG (now UGI Central). UGI Gas Exhibit C (Future) presents similar summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2019 ("FTY"). UGI Gas Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2018 ("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 Gas Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI Gas Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2020?

A. Yes.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

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

A. The depreciation study report in UGI Gas Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report submitted in 2019. 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 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, 2019. 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, 2019. 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 years 2015 through 2019.

UGI Gas Exhibit C (Fully Projected) 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, 2020. The descriptions and explanations presented in UGI Gas Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI Gas Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI Gas Exhibit C (Future) also support the service life estimates used in UGI Gas Exhibit C (Fully Projected), inasmuch as the estimates are the same for both test years, *i.e.*, Future and Fully Projected. The service life estimates set forth in UGI Gas Exhibit C (Historic) are the same estimates as those approved in the company's Annual Depreciation Reports submitted to the PUC in March 2018. The pro forma depreciation expense for the consolidated gas company at the end of the historic test year, September 30, 2018, is the sum of the three companies, UGI PNG, UGI CPG and UGI Gas, as they existed prior to their merger.

The results of the study are set forth in Part II in UGI Gas Exhibit C (Fully Projected). Table 1, pages II-4 through II-6 of UGI Gas Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2020, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-7 through II-8 of UGI Gas Exhibit C (Fully Projected), presents the bring-forward to September 30, 2020, of the depreciation reserve as of September 30, 2019. Table 3, pages II-9 through II-11 of UGI Gas Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, pages II-12 through II-13 of UGI

Gas Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2016 through 2020. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2015 through September 30, 2020. The summary tables and detailed depreciation calculations set forth in UGI Gas Exhibit C (Fully Projected) as of September 30, 2020, are organized and presented in the same manner as those presented in UGI Gas Exhibit C (Future) as of September 30, 2019.

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

A. UGI Gas Exhibit C (Historic) is organized similar to UGI Gas Exhibit C (Fully Projected). UGI Gas 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, 2018. The service life estimates used in the historic test year period were based on the survivor curve estimates set forth in the respective companies Annual Depreciation Reports (ADRs) submitted to the PUC in March 2018. The revised survivor curve estimates based on the consolidated service life study of all three companies was used in the future test year and fully projected future test year periods. The summary tables and detailed depreciation calculations as of September 30, 2018, are organized and presented in the same manner as those as of September 30, 2020 with two exceptions. Tables 2 and 3 presented in UGI Gas Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI Gas Exhibit C (Historic).

IV. THE DEPRECIATION STUDY - OVERVIEW

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 Class A and Class B Natural Gas Companies. "Depreciation" refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas 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, requirements of public authorities and the exhaustion of natural resources.

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. While the Company's case is based on a consolidated UGI Gas ratemaking basis, I also present the depreciation calculations on a rate district by rate district basis for the FTY and FPFTY in UGI Gas Exhibits C (Future) and (Fully Projected Future).

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in the most recent Annual Depreciation Reports filed for UGI Gas, UGI CPG, and UGI PNG in March 2018?

A. Yes, essentially it is, as I will explain later. 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 over thirty years. The depreciation methods and procedures are described further in Part II of UGI Gas Exhibit C (Future). All three companies used the average service life procedure (ASL) for their older vintages and the equal life group procedures (ELG) for their more recent vintages. The phase-in of the ELG procedure started in 1982 for UGI Gas and 1992 for UGI CPG and UGI PNG. For the consolidated company, the phase-in year proposed is 1982, the same as the former UGI Gas (now UGI South).

In a few subaccounts, there were some slight differences maintained by each of the three companies particularly when it came to the material types used for mains and services. This is not unusual as the assets were, for a long time, maintained by three different and unaffiliated companies. Going forward, with a new service life study performed in connection with this case, the depreciable categories or plant subaccounts to be maintained will be the same as those previously used by the predecessor UGI Gas.

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 gas plant to be included in rate base in this proceeding?

A. As of September 30, 2020, the original cost of gas plant in service is $3,950,991,155 as shown in column 4 of Table 1 on pages II-4 through II-6 of UGI Gas Exhibit C (Fully Projected). This amount includes $3,726,871,337 of Gas Plant and $224,119,818 of Other Utility Plant allocated to Gas Division. 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 between the Gas and Electric Divisions of UGI Utilities, Inc. The costs related to Common Plant and IS are allocated to Gas Division at 91.24 percent and 91.72 percent, respectively. In addition, the building that houses most of the IS assets, *i.e.*, the Reading Office and Service Center located on 225 Morgantown Road, is included in Account 390.1, Structures and Improvements in Gas Division. Since a portion of the building relates to IS, a portion of the cost attributable to the Electric Division was deducted from the Reading Office and Service Building.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI Gas's accrued depreciation for ratemaking purposes as of September 30, 2020?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2020, to be $1,072,874,830.

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 Gas's allocated book depreciation reserve as of September 30, 2019?

A. The book depreciation reserve allocated to Gas Division as of September 30, 2019, is set forth in column 5 of Table 1 of UGI Gas Exhibit C (Future). Table 2 of UGI Gas Exhibit C (Future) is an annual bring-forward of the book depreciation reserve as of September 30, 2018, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2018 through September 2019. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2018, the estimated reserve activity, and the ending reserve balance as of September 30, 2019. 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 Gas 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, 2018, by plant account, shown in column 2 of Table 2 was obtained from UGI Gas's books and records.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2019.

A. The depreciation accruals for the twelve months ended September 30, 2019, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2018, to the projected average 2019 plant balance. The average balance for the twelve months ended September 30, 2019, 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 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, 2013 through September 30, 2018.

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, for the five years 2014 through 2018, to FTY and FPFTY 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, as a percent of retirement amounts, for the five years 2014 through 2018, to the projected retirement amounts.

Q. Was the book reserve at September 30, 2020, estimated using the same methodology?

A. Yes, it was essentially the same methodology with one minor exception. The book depreciation accruals calculated for fiscal year 2020 were based on applying the monthly depreciation rate to average monthly plant balances for each month for purposes of calculating book depreciation accruals and used to calculate the book reserve as of September 30, 2020.

VII. THE ANNUAL DEPRECIATION EXPENSE CLAIM

Q. Have you determined UGI Gas'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 $109,081,567 and consists of $100,203,895 of annual accruals to recover original cost and $8,877,672 of net salvage amortization. These amounts are set forth in column 6 of Table 1 in UGI Gas Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $100,203,895?

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 I conducted in connection with this case, and in compliance with the Commission's requirements under 52 Pa. Code Section 73.5, consisted of: compiling historical data from records related to UGI Gas's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI Gas'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 for the purpose of estimating the service life characteristics of UGI Gas's gas plant?

A. The data I evaluated in connection with this most recent service life study consisted of the entries made by UGI Gas to record gas plant transactions during the period 1951 through 2017. 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 in these interpretations. The results of the retirement rate analyses are presented in Part VI of UGI Gas Exhibit C (Future).

Q. Please explain briefly what an "Iowa type survivor curve" is and how you use 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 35-R2 curve indicates an average service life of thirty-five years; a Right-skewed, or R, type curve (the mode occurs after average life for right modal curves); and a relatively low height, 2, 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. In connection with the development of the new service life study, field trips were conducted in order to enhance my familiarity with the operation of the company and observe representative portions of the plant. Facilities visited during field trips, generally include representative city gate stations, district regulating stations, service centers, etc. The most recent field trip was conducted over 2 days in August 2018. 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 analyses.

Q. Please describe the second phase of the process that you used in order 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 on Table 1 of UGI Gas Exhibit C (Historic), UGI Gas Exhibit C (Future) and UGI Gas Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and Part VII of UGI Gas Exhibit C (Future). Separate summary and detailed tabulations for UGI North, UGI Central and UGI South are also presented in the Exhibits listed above.

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.

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 very small percent of depreciable gas 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. All units are retired per books when the age of the vintage reaches the amortization period.

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 Gas Exhibit C (Future) using an account as an example.

A. I will use Account 376.1, Mains – Primarily Steel, to illustrate the manner in which the study was conducted. Account 376.1 represents 15 percent of the total depreciable gas plant. As the initial step of the service life study phase, aged plant accounting data were compiled for the years 1951 through 2017. These data have been coded in the course of UGI Gas's normal recordkeeping according to account or property group, type of transaction, year in which the transaction took place, and year in which the gas 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 primarily cathodically-protected, steel mains, although some bare steel mains are still in service. The Iowa 73-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The survivor curve estimates used in the previous service life studies varied for the three companies. UGI PNG (now UGI North) did not have a depreciation category (*i.e.*, subaccount) specifically related to steel mains; however, they did have a subaccount for all non-plastic mains (*i.e.*, steel, cast iron, wrought iron, etc.) that used the Iowa 72-R2.5 survivor curve. The estimate used by UGI CPG (now UGI Central) was the Iowa 62-R3 and this was the estimate used for all types of mains since UGI CPG did not use separate subaccounts for mains by material type. The current survivor curve estimate for the predecessor UGI Gas (now UGI South) is the Iowa 72-R2.5. The proposed Iowa 73-R2.5 survivor curve is a reasonably good fit for the original curve based on the company's retirement experience for the period 1951-2017. The proposed 73-R2.5 survivor curve is within the range of estimates used by other gas companies and is consistent with the outlook of company management. The original and smooth survivor curves are plotted in Part VI on page VI-40 of UGI Gas Exhibit C (Future). The original life table for the 1951-2017 experience band is set forth on pages VI-41 through VI-46.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service at September 30, 2019, is presented by vintage in Part VII on pages VII-55 through VII-63 of UGI Gas Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations at September 30, 2020 are presented in Part III of Exhibit C (Fully Projected). 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). 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 73-R2.5 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 73-R2.5 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 73-R2.5 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-63 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-5 of the exhibit and divided by the total original cost in column 4 in order to calculate the annual depreciation accrual rate in column 6. A similar process was used for the FPFTY.

Q. Is the procedure you described for Account 376.1 typical of that followed for most of the plant investment?

A. Yes, it is, inasmuch as 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 Gas 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, 2019, is presented by vintage in Part VII starting on page VII-159 of UGI Gas 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-160 of UGI Gas Exhibit C (Future) was brought forward to column 8 of Table 1 on page V-6 of UGI Gas Exhibit C (Future).

A similar process was performed for UGI Gas Exhibit C (Fully Projected) and UGI Gas 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, 2020, is presented by vintage on page III-159 of UGI Gas Exhibit C (Fully Projected) and summarized in Table 1 on page II-5.

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 Gas Exhibit C (Historic) and UGI Gas Exhibit C (Fully Projected) and in Part VII of UGI Gas Exhibit C (Future).

IX. THE NET SALVAGE AMORTIZATION CLAIM

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 UGI CPG (formerly PPL Gas Utilities Corporation's) 2006 rate filing (Docket No. R-00061398) and have been utilized by UGI Gas, UGI CPG, and UGI PNG in their rate cases ever since. 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 Gas's annual depreciation expense consists, in part, of $8,877,672 of net salvage amortization. How did you determine that amount?

A. The $8,877,672 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2015 through September 30, 2020. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI Gas, 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 Gas Exhibit C (Future) and Part IV of UGI Gas Exhibit C (Fully Projected).

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 I-A-5, I-A-6, and I-A-7. In general, these responses are self-explanatory. The response to I-A-5 is a comparison of the actual and projected book depreciation reserve with the calculated accrued depreciation as of the end of the historic, future and fully projected future test years, respectively. The response to I-A-6 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. The response to I-A-7 is the cumulative depreciated original cost by installation year as of the end of the test years. The amounts requested in response to I-A-7 are set forth in UGI Gas Exhibit C (Historic) and UGI Gas Exhibit C (Future) in the section titled “Cumulative Depreciated Original Cost”.

Q. Does this conclude your direct testimony?

A. Yes, it does.