BOOK III

UGI PENN NATURAL GAS, INC.

BEFORE

THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Information Submitted Pursuant to

Section 53.51 et seq of the Commission's Regulations

UGI PNG GAS STATEMENT NO. 1 – PAUL J. SZYKMAN
UGI PNG GAS STATEMENT NO. 2 – KINDRA S. WALKER
UGI PNG GAS STATEMENT NO. 3 – MEGAN MATTERN
UGI PNG GAS STATEMENT NO. 4 – PAUL R. MOUL
UGI PNG GAS STATEMENT NO. 5 – PAUL R. HERBERT
UGI PNG GAS STATEMENT NO. 6 – JOHN F. WIEDMAYER

ORIGINAL TARIFF
UGI PENN NATURAL GAS, INC. – PA P.U.C. NO. 9

DOCKET NO. R-2016-2580030

Issued: January 19, 2017 Effective: March 20, 2017

UGI PNG STATEMENT NO. 1 – PAUL J. SZYKMAN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 1

Direct Testimony of
Paul J. Szykman

Topics Addressed:	**Rate Filing Overview**
	Need for Rate Relief
	UGI-1 Initiative
	UNITE Systems Improvement Initiative
	Interruptible Revenues
	Management Performance

Dated: January 19, 2017

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Paul J. Szykman. My business address is 2525 North 12th Street, Suite 360, Reading, PA 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Vice President – Rates & Government Relations and Vice President & General Manager – Electric Utilities.

Q. Please briefly describe your responsibilities in that capacity.

A. As Vice President – Rates and Government Relations, I am responsible for all rate and governmental affairs activities for UGI Utilities, Inc. – Gas Division ("UGI Gas"), UGI Penn Natural Gas, Inc. ("UGI PNG" or the "Company"), UGI Central Penn Gas, Inc. ("UGI CPG") 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, 1307(f) gas cost filings, electric POLR filings, 1307(e) filings and UGI's gas management information technology systems.

As far as government relations are concerned, I am responsible for managing the development and implementation of the Company's strategies in federal and state legislative and regulatory arenas.

Lastly, I am responsible for operations management of UGI Electric. In all of these capacities, 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 PNG Exhibit PJS-1, which is attached to my testimony.

Q. Have you testified previously before this Commission?

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

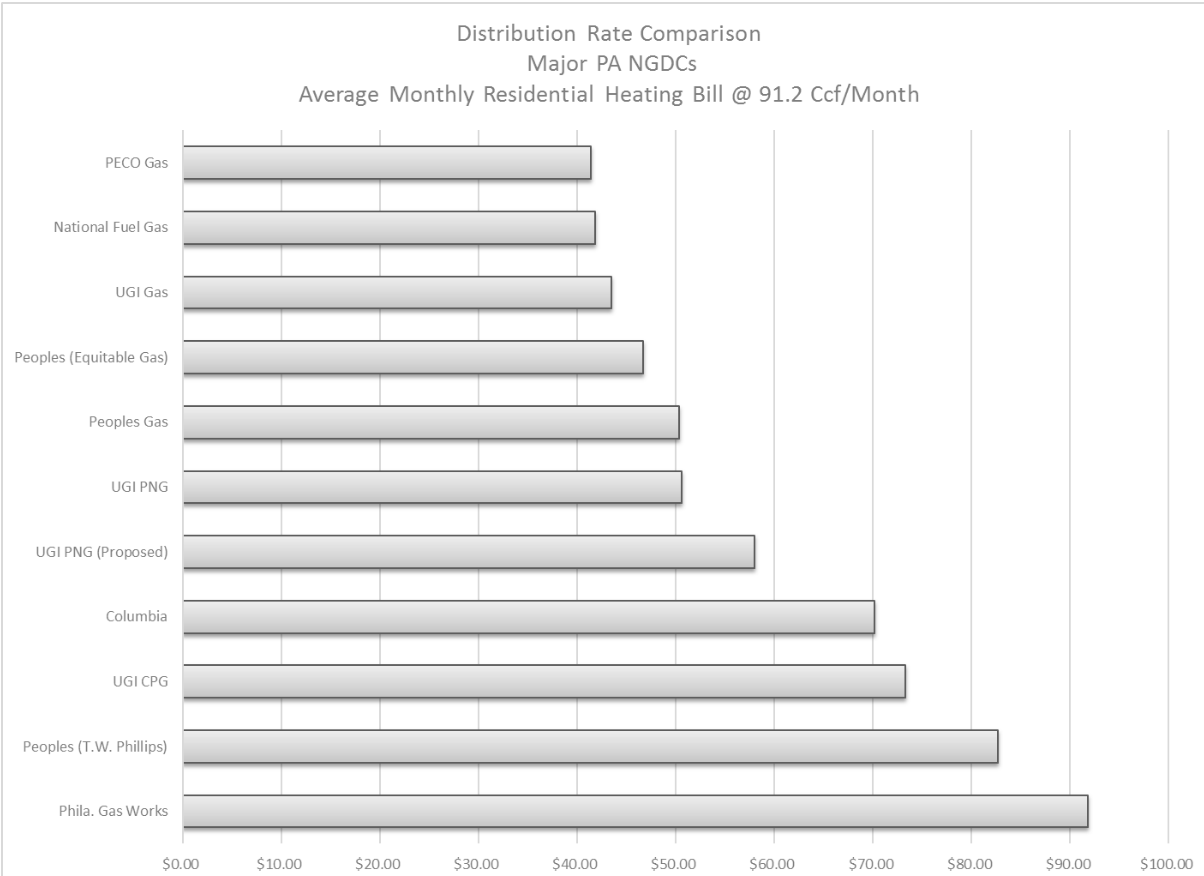
II. PURPOSE OF TESTIMONY

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 UGI-1, an initiative designed to align UGI's people, processes and tools across the utility business units. As part of my UGI-1 discussion, I briefly discuss the UGI's Next Information Technology Enterprise ("UNITE") Initiative, which is UGI's ongoing effort to develop and implement a next generation technology solution, including a state-of-the-art customer information system ("CIS") and other work management and regulatory compliance programs, and summarize the benefits that UNITE will bring to UGI PNG's Customers. Third, I discuss the Company's interruptible service program and how continuing value of service pricing and a reasonable cost of service allocation for those customers is reasonable and appropriate. Lastly, I will summarize UGI PNG'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 PNG's management continues to improve service to customers through various initiatives, including, but not limited to: the UGI-1 initiative; the UNITE system improvement initiative; an accelerated infrastructure replacement plan; an innovative expansion and extension program; supporting customer growth; customer service that has generated nationally recognized customer satisfaction; implementation of recently expanded universal services offerings; development of an energy efficiency and conservation plan; development of flexible customer-focused rate alternatives, *i.e.,* the Technology and Economic Development ("TED") Rider; a focus on diversity within the organization; and dedication to continuous safety improvement initiatives.

At the same time, the Company has been able to offer excellent service to customers at reasonable rates. A comparison of residential rates, shown in Table 1 below, illustrates that UGI PNG's current distribution rates are reasonable.

Table 1



Even if the proposed increase is approved in full, the average monthly residential heating customer bill will be 39% lower than the average bill following UGI PNG's last rate case in 2009.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to UGI PNG Exhibit PJS-1 mentioned above, I am sponsoring certain responses to the Commission's filing requirements. Each filing requirement response identifies the witness sponsoring it. Specifically, I am sponsoring those schedules that were prepared by me or under my direction as appropriately identified in this filing.

III. OVERVIEW OF THE COMPANY'S FILING

Q. Please discuss the rate relief that UGI PNG is requesting.

A. UGI PNG is requesting an increase in its annual base rate operating revenues of $21.7 million, or 10.4 percent on a total revenue basis, with a proposed effective date of March 20, 2017. The base rate increase requested in this filing is based on a fully projected future test year ending September 30, 2018 ("FPFTY"). The Company also proposes certain changes to its existing tariff to both harmonize the UGI PNG tariff with those previously approved by the Commission for UGI Gas and UGI CPG and to continue the Company's approach of implementing best practices and procedures. The Company also is proposing a new five-year energy conservation program, the Energy Efficiency and Conservation ("EE&C") Plan, designed to promote efficient use of natural gas. This program is patterned off the recently approved EE&C plan for UGI Gas. Finally, the Company is proposing a pilot Technology and Economic Development ("TED") Rider to, among other things, provide rate flexibility needed to encourage developing technologies, and to address competitive conditions and customer preferences in seeking to expand the availability and use of the Commonwealth's abundant natural gas supplies. UGI PNG's TED Rider is patterned off the 3-year TED Rider pilot for UGI Gas which was approved as part of the recent UGI Gas base rate case.

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

A. The Company's current rates do not provide it with a reasonable opportunity to earn its cost of capital. Since its last rate case in 2009, UGI PNG has made nearly $400 million in system investments, increasing the Company's rate base by nearly 31 percent. These investments were necessary to serve new residential and commercial customers; connect customers converting to natural gas; accelerate the replacement of aging gas plant infrastructure; upgrade and improve system segments and modernize facilities; and install and upgrade supporting information technology, all as part of growing and maintaining a safe and reliable distribution system and providing quality customer service. While UGI PNG has received a return on and of certain portions of these investments through its Distribution System Improvement Charge ("DSIC"), UGI PNG's DSIC charge has reached the current cap of five percent (5%) of distribution revenues, effectively preventing a reasonable return on additional DSIC eligible investment amounts outside of filing a base rate case. Since its last base rate case, UGI PNG has 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 PNG has implemented significant cost containment measures, implemented efficiency enhancements including major strides toward integrating its operations with those of UGI Gas and UGI CPG, and seen stable customer growth over time, the growth in operating and capital costs, along with experienced and anticipated declines in per customer usage, are causing UGI PNG to be unable to earn a fair rate of return on its investment, at present rate levels.

Specifically, as reflected in UGI PNG Gas Exhibit A (Fully Projected), Schedule A-1, the Company's operations are projected to produce an overall return on rate base of 6.15%, which equates to a return on common equity of only 7.15% for the twelve months ending September 30, 2018. As explained by UGI PNG witness Paul R. Moul (UGI PNG Statement No. 4), those returns are not adequate based on applicable financial data and the risks confronted by UGI PNG. Unless UGI PNG receives the requested substantial rate relief, those returns will continue to decline and potentially jeopardize the Company's ability to attract the capital needed to make system investments that will enhance the reach and capacity of its distribution system and to replace older, obsolete facilities, each of which is prudent to ensure continued system reliability, safety, and customer service performance.

Q. Please identify the other witnesses providing direct testimony on behalf of UGI PNG 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:

Kindra S. Walker (UGI PNG Statement No. 2) serves as Senior Director, Finance at UGI. Ms. Walker explains UGI PNG's budgeting processes and revenue requirement exhibits for the historic test year ended September 30, 2016 ("HTY"), future test year ending September 30, 2017 ("FTY"), and the fully projected future test year ending September 30, 2018 ("FPFTY"). Ms. Walker also presents testimony on how the Company's capital spending satisfies the requirements of recently enacted Section 1301.1 of the Public Utility Code.

Megan Mattern (UGI PNG Statement No. 3) serves as Controller at UGI. Ms. Mattern addresses the Company's accounting processes. She also presents the Company's rate base development for the HTY, FTY, and FPFTY. Ms. Mattern also addresses a *pro forma* adjustment to the Company's HTY, FTY and FPFTY schedules associated with cloud-based technology services.

Paul R. Moul (UGI PNG Statement No. 4) is Managing Consultant of P. Moul & Associates, Inc. Mr. Moul presents expert testimony concerning the overall rate of return that UGI PNG should be afforded in order to have a reasonable opportunity to earn a fair return on its rate base investment. Mr. Moul also supports the Company's claimed capital structure, its embedded cost of debt, as well as its requested return on common equity. Schedules and work papers supporting Mr. Moul's findings are set forth in UGI PNG Exhibit B.

Paul R. Herbert (UGI PNG Statement No. 5) is President of Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Herbert prepared and sponsors the Company's fully allocated cost of service studies used in this case, which are found in UGI PNG Exhibit D.

John F. Wiedmayer (UGI PNG Statement No. 6) is Project Manager at Gannett Fleming Valuation & Rate Consultants, LLC. Mr. Wiedmayer developed and supports the Company's claim for annual depreciation expense and the accumulated depreciation reserve. His studies are presented in UGI PNG Exhibit C (Fully Projected), UGI PNG Exhibit C (Future) and UGI PNG Exhibit C (Historic).

David E. Lahoff (UGI PNG Statement No. 7) serves as Manager – Tariff & Supplier Administration at UGI. Mr. Lahoff is responsible for all areas of the Company's rate design and revenue allocation except where I discuss interruptible service pricing in my testimony. Mr. Lahoff also addresses and sponsors related exhibits that show the proof of revenues and proposed rate design, as presented in UGI PNG Exhibit E - Proof of Revenue. Mr. Lahoff's testimony also presents the detailed supporting sales and revenue adjustments for each tariff customer class, including related models and assumptions.

Mr. Lahoff is also sponsoring UGI PNG Exhibit F, which is Original Tariff – Gas Pa. P.U.C. No. 9 ("Tariff No. 9"), which replaces current Tariff – Gas Pa.

P.U.C. No. 8. Mr. Lahoff provides a summary of the proposed changes to the tariff rules, regulations, and rate schedules included in UGI PNG's Tariff No. 9, and changes to the Choice Supplier Tariff, which is incorporated into Tariff No. 9 as Tariff No. 9-S. Mr. Lahoff also provides an explanation of the EE&C Rider, Merchant Function Rider, Universal Service Program Rider, and Growth Extension Tariff ("GET Gas") Rider.

Robert R. Stoyko (UGI PNG Statement No. 8) is Vice President, Marketing and Customer Relations at UGI. Mr. Stoyko explains and provides support for the Company's proposed TED Rider pilot, large customer usage projections, customer service performance metrics, and implementation plans for the Company's proposed EE&C Plan.

Chris Ann Rossi (UGI PNG Statement No. 9) is the Director – Customer Services at UGI. Ms. Rossi addresses the Company's Universal Service Plan Rider ("USP Rider"), and identifies changes to UGI PNG's customer service policies and procedures implemented to align with changes adopted by UGI Gas in its most recent general rate case at Docket No. R-2015-2518438.

Hans Bell (UGI PNG Statement No. 10) is Vice-President Engineering & Operations Support at UGI. In his testimony, Mr. Bell provides an overview of UGI PNG's operations and discusses the Company's natural gas distribution system, its Commission-approved Long Term Infrastructure Improvement Plans ("LTIIP"), and the Company's performance against its infrastructure replacement and improvement objectives. Mr. Bell also discusses the impact of the LTIIP and other initiatives on system performance, safety, and reliability. Additionally, Mr. Bell discusses the changes to the Company workplace safety program and the favorable impact those changes have had on various employee safety performance metrics. Finally, Mr. Bell addresses the Company's enhanced efforts and future plans to investigate and, where necessary, remediate sites in Pennsylvania where the Company or corporate predecessors once owned and operated manufactured gas plants in connection with gas utility operations.

Nicole McKinney (UGI PNG Statement No. 11) is Principal Tax Analyst at UGI. Ms. McKinney addresses 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 ratemaking treatment of the impact of the Company's repairs tax method election on federal and state income taxes, and issues pertaining to UGI PNG's participation in a consolidated group for federal income tax purposes.

Theodore M. Love (UGI PNG Statement No. 12) is Senior Analyst of Green Energy Economics Group, Inc. Mr. Love presents the Company's proposed EE&C Plan and discusses its costs and benefits. As part of this presentation, Mr.

Love also provides the results of an analysis applying the total resource cost ("TRC") test. Mr. Love also discusses the implementation schedule for the EE&C Plan.

Angelina M. Borelli (UGI PNG Statement No. 13) is the Director - Gas and Electric Supply at UGI. Ms. Borelli describes UGI PNG's proposed capacity release program for Rate DS (Delivery Service) and certain Rate LFD (Large Firm Delivery Service) transportation customers.

IV. <u>UGI-1 INITIATIVE</u>

Q. Please describe the UGI-1 initiative.

A. UGI-1 is a company-wide improvement initiative focusing on people, tools and processes. UGI PNG and its utility affiliates have a history of pursuing excellent performance for its customers, employees and shareholders. Moving forward, the Company plans to build on this past performance and provide even better service in the future. Over the past few years, UGI PNG has experienced stable growth opportunities as well as significant operational challenges. To act on these opportunities and to address these challenges, UGI PNG is taking advantage of synergies, equipping employees for future success, and improving communications throughout the organization. By implementing these initiatives, UGI PNG will position itself for continued growth and success and outstanding customer service.

UGI-1 includes a number of fundamental improvement efforts, including such programs as: UNITE technology improvement project; UGI PNG's "Making a Difference" safety improvement program; the migration of all employee computer workstations to a set of common workplace applications; the migration of all field employees to a single set of gas operations and construction processes and specifications; UGI PNG building and grounds improvements and renovations; UGI PNG's natural gas pipeline facility extension and betterment programs; an enhanced focus on physical and cyber security; and a range of enhanced and expanded employee development and training programs.

Q. How do the changes envisioned by UGI-1 benefit customers?

A. The overall goal of UGI-1 is to place all of our operations on a common set of information systems, tools, equipment, and uniform work management and performance platforms. This will allow the Company 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 the gas distribution system, and managing emergencies. An effective and common system of performing and measuring performance among our geographically disparate service territories and segments thereof will also expedite identification of problems that can be corrected more readily or even before they happen, driving further efficiency gains and service improvements.

Fully integrating three separately regulated natural gas distribution systems (UGI Gas, UGI CPG, and UGI PNG) and one electric distribution system will enable the Company to ensure that costs incurred to provide service reflect a common way of doing our work. This will help eliminate differences in cost drivers among the three regulated natural gas distribution systems, to the extent feasible and where geographic or industry (natural gas versus electric) factors do not dictate the result.

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

A. There have been several improvements in the operations area. For example, UGI PNG has made a concerted effort to establish and implement a common methodology for rating the severity of natural gas system leaks to place UGI Gas's, UGI CPG's and UGI PNG's distribution systems in line with the Gas Pipeline Technology Committee standard. Now that this common rating system has been established and implemented, UGI PNG is better situated to allocate its pipeline replacement, leak survey and repair, financial, internal labor, and contractor resources to the segments of the UGI Gas, UGI CPG, and UGI PNG distribution systems that require the most attention based on uniform measures of risk. This common approach to regulatory compliance has achieved significant improvements to system safety performance over the past two years, including reductions in hazardous leaks and leak inventories. As discussed further in the direct testimony of Mr. Bell (UGI PNG Statement No. 10), UGI PNG's common set of initiatives in workplace safety, Pennsylvania 1-Call, and 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 PNG's customer base has grown by nearly 8%, or by over 12,000 customers, since its last base rate case.[1] This growth, along with that of UGI Gas and UGI CPG, has been supported by business changes that focus on the new customer process and performance.

More recently, UGI PNG's Commission-approved GET Gas Pilot Program 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 territory.

Also, as part of UGI's UNITE initiative, recently approved tariff provisions for UGI PNG and UGI Electric will allow joint billing of natural gas and electric services on one bill for UGI customers who receive both gas and electric service from UGI, providing for greater customer convenience and customer satisfaction.

In this case, the Company's proposed pilot TED Rider and EE&C

[1] Comparison based on 2018 Future Test Year customers of 169,052 compared to PNG 2009 base rate case customers of 156,934.

Program, as discussed in more detail below, further demonstrate the Company's commitment to expand its customer base and to do so in an effective, efficient, economic and environmentally friendly manner.

Q. Why is the Company proposing an energy efficiency and conservation program?

A. UGI PNG's proposal is consistent with its environmental efforts and approach towards customer service. The EE&C Plan will provide customers with a financial incentive to install higher efficiency gas burning appliances and equipment. The resulting reduction in consumption will provide savings to customers who take advantage of the program, as well as environmental benefits and downward pressure on natural gas prices to the benefit of all customers. Moreover, UGI PNG believes key elements of the EE&C Plan, including greater combined heat and power (CHP) and direct use natural gas applications, focus not just on the efficient use of natural gas, but on the most efficient use of all energy resources. A more detailed discussion of this program and its benefits is provided in the testimony of Mr. Love (UGI PNG Statement No. 12).

Q. Has the Company undertaken any recent initiatives to assist low income customers to afford their natural gas service?

A. In its most recent triennial review at Docket No. M-2013-2371824, UGI PNG received approval from the Commission to implement several new components to its Universal Service Programs that should assist low income customers, including eliminating the maximum level of low income customers that can be served under the Company's Customer Assistance Program ("CAP").

As explained in the direct testimony of Ms. Rossi (UGI PNG Statement No. 9), UGI Gas agreed as part of a Commission-approved settlement in the UGI Gas 2016 base rate case at Docket No. R-2015-2518438 to implement certain customer service-focused practices and procedures – some of which impact the administration of the USECP. As the UGI Distribution Companies manage their Customer Operations collectively, these changes have been implemented for UGI PNG's customers as well.

Q. You mentioned earlier in your testimony the Company's UNITE initiative as part of UGI-1. Please discuss.

A. As noted earlier, UNITE stands for UGI's Next Information Technology Enterprise. UNITE is designed to replace and update UGI PNG's core, non-financial computer systems including the Customer Information System ("CIS"). Principally, with regard to the CIS replacement work, two aging CISs will be replaced with one state-of-the-art system, which UGI PNG will share with its utility affiliates. Having a common CIS for all four of its utility business (UGI Gas, UGI Electric, UGI CPG, and UGI PNG) will allow UGI PNG to benefit from a common set of processes so that it can maximize the efficiency of rendering service to its customers at a reasonable cost. This initiative will allow employees system wide to provide safer and more reliable service in the field and to address other concerns related to billing and affordability of service. Importantly, this new system will also support key Choice customer business processes, including seamless moves, instant connects and 3-day switching, as may be required. UNITE will address a number of objectives including: reducing operational risks related to the age of certain applications where there is no vendor support and the people who know the systems best are retiring; improving operational capabilities with new "scalable" technology platforms; standardizing and reducing the number of systems and duplicate processes across UGI; improving business information to make more informed business decisions; and gaining efficiency related to process and system integration.

Q. Has the Company made other efforts to make the Company's service more economic for its customers?

A. Yes. A series of gas portfolio changes allow UGI PNG and Natural Gas Suppliers serving Choice customers on the UGI PNG system to maximize the purchase of natural gas from the Marcellus and Utica Shale sources. While the majority of UGI PNG's natural gas purchases were from the Gulf region in the past, today nearly all of UGI PNG's natural gas purchases are physically sourced from Marcellus and Utica Shale sources. The impact related to shale gas on pricing has been significant. At the conclusion of UGI PNG's last base rate case in August 2009, UGI PNG's Purchased Gas Cost ("PGC") rate was $10.40/Mcf;

comparatively, UGI PNG's current PGC rate is just $3.15/Mcf. This 70% reduction in gas costs not only represents the significant impact shale production has had on natural gas pricing nationwide, but it also demonstrates the impact of UGI PNG's efforts to focus on creating value for its customers by working to reshape its supply portfolio and reduce now unnecessary long haul pipeline transportation costs.

V. <u>INTERRUPTIBLE REVENUES</u>

Q. Please explain the Company's proposal relative to revenues received under its Interruptible Service rates.

A. As explained in the testimony of Mr. Stoyko (UGI PNG Statement No. 8), the construction of natural gas distribution systems is very capital intensive. However, 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 UGI PNG's largest customers, and for those with installed alternate fuel capabilities. UGI PNG currently provides interruptible gas service to 33 customers under contracts voluntarily entered into that have rates based on the alternatives available to such customers.

As a result of the capital-intensive nature of natural gas distribution systems, all customers benefit if costs can be shared over a larger customer base. However, due to the market risks presented by customers with installed alternate fuel capabilities served under interruptible rate schedules, UGI PNG 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. To reflect this business reality in cost allocation, Mr. Herbert presents two cost of service studies in support of a proper allocation of costs to the interruptible market: one which allocates main costs to the interruptible class via the average and excess method outlined by Mr. Herbert, and one which allocates no main costs to interruptible customers. The Company has based its revenue allocation for interruptible customers based on the average of the results of these two cost of service studies, while continuing to price interruptible customers based on market conditions. This approach properly reflects both cost of service and value of service principles and provides a balanced and reasonable basis for setting rates while providing incentive to the Company to maximize interruptible revenues and develop shared value for the interests of customers and the Company. Specifically, UGI PNG proposes to (1) establish the overall revenue requirement and revenue allocation for interruptible customers based on the average cost of service method described above, or an amount of $945,000, (2) continue to charge interruptible service customers value of service prices, and (3) retain or absorb any difference between cost of service and value of service pricing between rate cases.

Q. Please explain how value of service pricing assists the Company in managing its business risk.

A. Value of service pricing, to the extent that the Company can charge rates above a proxy cost of service that allocates reasonable mains investment to interruptible customers, provides the Company with an additional source of revenue to maintain a return on investment for the total enterprise that meets the expectations of its shareholders in return for assuming the risks of the associated revenue requirement offset. All else being equal, in years where temperatures are warmer than normal, revenue generated from the interruptible market helps UGI PNG to earn a more stable return. Similarly, as weather becomes colder than normal, firm usage increases and interruptible usage and related revenue declines as distribution capacity becomes constrained and interruptions are implemented for this market segment. Moreover, as usage per customer in the UGI PNG core market is projected to decline, having interruptible revenue that may contribute to earning a reasonable return will continue to support necessary capital attraction at reasonable rates.

Q. Please discuss how value of service pricing provides a source of capital for use in the Company's capital improvement program.

A. The revenue generated from interruptible customers provides greater cash flows that are available for the Company to finance its operations. These increased cash flows would not be available if interruptible rates were determined strictly on cost of service principles.

Q. Why is value of service pricing appropriate for the interruptible market?

A. Value of service pricing is appropriate for two principal reasons. First, interruptible customers have competitive alternatives and are capable of choosing those alternatives and leaving the UGI PNG system at any time. It is reasonable under these circumstances, in the Company's view, to charge these customers competitive prices because they have competitive alternatives. Cost of service pricing is more appropriate and indeed is designed for regulated monopoly conditions, which by definition do not exist where customers have competitive alternatives. Strict cost of service pricing is not appropriate where a customer group has verified competitive alternatives for gas service and can leave the utility system at any time.

Second, and relatedly, interruptible customers have the option to become firm customers and take service under a cost-based firm service rate if they choose to do so, and to the extent that the system has sufficient capacity to allow for a conversion to firm service or if they contribute sufficient capital to finance the investment necessary to render firm service.

In summary, the Company's proposal to provide a fixed offset to revenue requirement equal to the proxy cost of service for the interruptible market using an average main allocation approach, in exchange for assuming the ongoing risks related to serving this competitive market under value of service pricing, appropriately reflects both cost of service and value of service pricing principles, properly recognizes the competitive alternatives available to interruptible customers, and provides important benefits to all customers that would not be available under strict cost of service principles.

VI. MANAGEMENT EFFECTIVENESS AND PERFORMANCE

Q. Please summarize the Company's initiatives and activities related to management performance.

A. UGI PNG has focused on a number of areas to enhance and improve the quality and effectiveness of UGI PNG's 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 PNG Statement No. 10). UGI PNG already is a leader in the Commonwealth, as its distribution system is among the highest in the percentage of contemporary mains. See Table 2 below. Moreover, as shown in UGI PNG's LTIIPs filed in accordance with Act 11, the Company projects that it will eliminate all UGI PNG system 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.

Table 2

Percent Contemporary Distribution Main among PA NGDCs, per 2015 DOT reporting	
UGI Gas	87.5%
UGI PNG	84.5%
PECO	83.0%
UGI CPG	82.7%
Columbia	78.7%
National Fuel	75.6%
Peoples	69.7%
PGW	32.0%

- Developing and implementing an innovative expansion and extension program (GET Gas), which will invest $25 million in UGI PNG's service territory as part of a total $75 million commitment across the UGI companies to reach new customers in unserved and underserved areas. The pilot GET Gas program has been highlighted nationwide at American Gas Association events and has been called a model program.
- Proposing to implement a new pilot rider, 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 Robert R. Stoyko (UGI PNG Statement No. 8).
- Managing growth with an increase in overall customer counts of nearly 8% since UGI PNG's last base rate case in 2009. All else being equal, this growth has helped reduced 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 4 years, and winning the award a total of 7 times (2003-2007, 2013, 2014) since UGI was first included in the survey in 2003 by J.D. Power, as further explained in the testimony of Robert R. Stoyko (UGI PNG Statement No. 8).
- 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 PNG Statement No. 10). These initiatives include pursuing OSHA verification of a Voluntary Protection Program ("VPP"), a First Move Forward policy, a 360-degree "cone" policy, a "Making a Difference" safety program, use of dash-cams to record and review incidents or close-calls, Smith Driving School training, an annual Safety Summit involving all employees, establishing safety committees for root cause analysis and review, and Company-wide education and appropriate employee coaching and engagement tracks.
- Pursuing a focus on employee diversity. In the most recent 5 years across all UGI business units, approximately 50% of all new employees have come to UGI as female or minority candidates.
- Focusing on increasing spend with Minority and Women-Owned Businesses ("MWBEs"). Internal initiatives to increase focus on our WMBE 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 PNG's Purchasing Supervisor is a Certified Professional in Supplier Diversity (C.P.S.D.).

- Launching a Company-wide initiative, UGI-1, which is aligning UGI PNG'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. As previously discussed, the UNITE Project is an information system modernization project. Phase 1 of the Project entails the development and implementation of a new CIS to replace our two legacy mainframe CIS systems. This new CIS will harmonize the two systems and provide increased functionality and improved customer service.
- Proposing to implement an EE&C Plan. The EE&C Plan is a comprehensive portfolio of energy efficiency and conservation programs that was designed to assist customers save energy through various cost-effective measures. The full contents of the EE&C Plan are described in detail in the direct testimony of Theodore M. Love (UGI PNG Statement No. 12).

In addition to these management efforts, it should be noted that UGI PNG continues to provide excellent service to customers as further explained in the direct testimony of Robert R. Stoyko (UGI PNG Statement No. 8). The above-described initiatives, as well as those described by the other witnesses, demonstrates UGI PNG's commitment to and focus on providing and improving safe and reliable distribution services to its customers.

It also should be noted that, as shown earlier, current UGI PNG residential distribution rates are very reasonable and that even if UGI PNG's proposed residential rates are implemented, the average monthly bill for a residential heating customer will be 39% lower today than the average bill following the Company's last base rate case in 2009.

The Company believes that the management efforts described above and the other improvements described by the UGI PNG witnesses in this proceeding, as well as the Company's provision of safe and reliable service at reasonable rates, support an additional upward adjustment to the Company's rate of return in recognition of its management effectiveness, which is included in the 11.20% equity return presented in this request.

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

A. Yes. For example:

- Each year UGI invests more than $1.5 million to support education improvement programs across the Company service territory, including $250,000 in the UGI PNG service territory. UGI PNG 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 PNG employees also commit significant personal time and resources to support community initiatives. For example, 147 UGI PNG employees donated more than 17,465 hours to assist their communities in 2015. UGI PNG employees also donated personal funds to better their communities, including approximately $25,000 contributed by UGI PNG employees as part of the Company's 2016 United Way campaign. Combined with Corporate contributions, total support provided to United Way agencies serving communities in the UGI PNG service territory in 2016 totaled more than $92,000.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI PNG EXHIBIT PJS-1

PAUL J. SZYKMAN

VICE PRESIDENT – RATES & GOVERNMENT RELATIONS
VICE PRESIDENT & GENERAL MANAGER – ELECTRIC UTILITIES

March 2015 – Present	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, R-00016376, R-00016376C0002, P-00032043, P-00032054, R-00049422, R-00050539, R-00061502, R-00072334, R-00072335, R-2008-2039284,R-2008-2039417, R-2008-2079675, R-2008-2079660, R-2009-2105911, R-2009-2105904, R-2009-2105909, R-2010-2214415 and R-2015-2518438.

UGI PNG STATEMENT NO. 2 – KINDRA S. WALKER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 2

Direct Testimony of
Kindra S. Walker

Topics Addressed:	**Budget Process** **Revenue Requirements** **Operating Revenues and Expenses**

Dated: January 19, 2017

I. INTRODUCTION

Q. Please state your name and business address.

A. Kindra S. Walker, 2525 North 12th Street, Reading, Pennsylvania 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Senior Director, Finance. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's subsidiaries include two wholly-owned natural gas distribution companies, UGI Central Penn Gas, Inc. ("UGI CPG"), and UGI Penn Natural Gas, Inc. ("UGI PNG"), that are regulated by the Pennsylvania Public Utility Commission ("Commission" or "PUC").

Q. What are your responsibilities as Senior Director, Finance?

A. I have overall responsibility for much of the financial area for UGI, UGI PNG, and UGI CPG. My duties currently include financial planning, budgeting and forecasting, and the coordination of these functions with UGI's Chief Financial Officer as well as the financial planning team at UGI Corp.

Q. What is your educational background?

A. I received a Bachelor's degree in English from Barnard College at Columbia University, and a Master's of Business Administration, Accounting from the Stern School of Business at New York University.

Q. Please describe your professional experience.

A. Since receiving my MBA, I have worked in a variety of finance and accounting positions of increasing responsibility. I began my professional career at Coopers & Lybrand where I achieved the position of Audit Manager before leaving in 1996. Afterwards, I worked for Trexler-Haines, Gas, Inc., as Controller and Director, Management Information Systems until 2000. I then spent the next four years as Director of Operations (CFO/COO) for The Dubbs Company, where I managed the day-to-day operations, finances and human resources. During the next two years, I taught various accounting and finance courses at Lehigh University and Kutztown University. From 2005 until I began my career at UGI earlier this year, I worked for over 10 years at PPL Services Company, a shared service provider owned by PPL Corporation. At PPL, I held several position, primarily in the U.K. regulated segment, including five years as Controller, International, where I worked extensively with the U.K. utility regulatory framework.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI PNG in support of the Company's proposed revenue requirement. First, I will explain UGI PNG's budgeting processes (Part III). Next, I will present UGI PNG's ratemaking presentations for the historic test year ended September 30, 2016 ("HTY"), future test year ending September 30, 2017 ("FTY") and the fully projected future test year ending September 30, 2018 ("FPFTY"), including its principal accounting exhibits, operating expenses claims, and certain *pro forma* adjustments (Part IV). To be clear, the Company's rate proposal in this case is predicated on its fully projected future test year exhibit. Lastly, I present testimony on how the level of the Company capital budget and spend satisfy the requirements of recently enacted Section 1301.1 of the Public Utility Code.

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

A. Yes, I am sponsoring UGI PNG Gas Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic). Other Company witnesses present testimony in support of various portions of these exhibits, including rate base (Megan Mattern, UGI PNG Statement No. 3), operating revenue (David Lahoff, UGI PNG Statement No. 7), fair rate of return (Paul Moul, UGI PNG Statement No. 4), and depreciation expense (John Wiedmayer, UGI Statement No. 6). I am also sponsoring those responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

II. OVERVIEW OF PRINCIPAL ACCOUNTING EXHIBITS

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

A. UGI PNG Exhibit A (Fully Projected) provides the calculation of the revenue requirement for the Fully Projected Future Test Year ending September 30, 2018, including principal accounting exhibits, rate base claims, operating expenses claims, and certain *pro forma* adjustments. The FPFTY information is derived from UGI PNG's operating and capital budgets for the 12 months ending September 30, 2018. UGI PNG Exhibit A (Future) is the principal accounting exhibit for the future year ending September 30, 2017, including certain *pro forma* adjustments. The Future year information is derived from UGI PNG's operating and capital budgets for the 12-month period ending September 30, 2017. UGI PNG Exhibit A (Historic) is the principal accounting exhibit for the historic year ended September 30, 2016, with appropriate ratemaking adjustments. The Historic year information is derived from the book accounting data for the 12-months ended September 30, 2016. 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 PNG's proposed revenue increase.

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

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

<u>Section A</u> summarizes UGI PNG's requested rate base, revenues, and expenses at present rates and the calculation of its requested revenue increase.

<u>Section B</u> includes basic accounting data extracted primarily from UGI PNG'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 PNG's embedded cost of debt, year-end capital structure and overall claimed rate of return.

<u>Section C</u> provides the elements of UGI PNG's rate base claim and how each element of that claim is derived. UGI PNG'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.

<u>Section D</u> presents UGI PNG'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 PNG's *pro forma* income at present and proposed rates as set forth in Schedule A-1.

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

A. UGI PNG Exhibits A (Historic) and A (Future) follow the format of UGI PNG Exhibit A (Fully Projected), but reflect data for the fiscal year ended September 30, 2016, and the fiscal year ending September 30, 2017, respectively. This information is provided to comply with the Commission's filing requirements, and provides a basis for comparing our FPFTY claims with actual and projected results from the HTY and FTY.

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

A. This data is derived from the UGI PNG's books and records, and capital and operating budgets. UGI PNG Exhibit A (Future) is based on adjusted budgeted data for the year ending September 30, 2017. UGI PNG Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2016.

III. <u>BUDGETING PROCESS</u>

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

A. UGI PNG's fiscal year begins on October 1 and ends on September 30 of the following year. Preparation of the UGI PNG Operating Budget for the subsequent fiscal year begins during the spring, *i.e.*, the budget for the October 1, 2016 through September 30, 2017 fiscal year, was prepared in the spring of 2016.

The revenue portion of the budget is a joint effort between the Marketing and Rates Departments. The Marketing Department provides customer growth and attrition information by customer class along with specific large commercial and industrial sales and revenue budget projections. The Rates Department develops normalized usage per customer for core customer classes, annualized sales and total revenues. The number of customers by customer class is determined using a wide range of factors, including trends in usage, the level of applications and inquiries for service from existing customers, new construction, the cost of competing fuels, and shifts in type of residence and customer mix. Usage per customer is developed by reviewing the most recent year's usage trends adjusted to normal weather conditions, the price of competitive fuels relative to natural gas, and current and anticipated levels of operation. The budgeted number of customers and usage per customer are combined to produce monthly budgeted sales. The revenue budget is calculated by applying tariff rates for each customer class to budgeted sales, plus an adjustment for unbilled revenue. The sales and revenue budget is then reviewed with and approved by senior management.

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, new or changed programs, and inflation. They are submitted for review and approval by senior management. UGI PNG expenses are then consolidated with allocated expenses from affiliated companies to develop the budgeted Statement of Operations. Allocated expenses in the Statement of Operations include functions such as accounting, rates, gas supply, human resources, information systems, payroll, and remittance processing, which are performed in accordance with PUC-approved affiliated interest arrangements or agreements.

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 PNG 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 PNG Capital Budget is prepared in conjunction with the Operating Budget. Operating personnel in each functional area prepare a detailed list of capital projects. Each project is identified, described and justified along with a breakdown of the costs associated with it. These projects are presented to senior management, which reviews them in terms of priorities, capital availability, and strategic alignment with the operating budget. After due consideration, the Capital Budget is set and presented, along with the Operating Budget, to senior management in a series of review meetings. Additional information concerning the factors considered in establishing the UGI PNG Capital Budget is provided in the direct testimony of Hans G. Bell (UGI PNG Statement No. 10).

With the passage of Act 11 of 2012, UGI PNG has also 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; however, the starting point for the additional year is the FTY budget. The FTY revenue budget is based on normalized weather conditions, per customer usage trends, and assumptions concerning growth in numbers of customers. Similarly, FTY budget expense amounts are adjusted for salary and personnel increases, known program changes and expense needs, and inflation. For the capital budget, known capital projects are included based on the process described above, and also described in the Mr. Bell's testimony (UGI PNG Statement No. 10). Additional assumptions also are made for emergent new business and other capital expenditures based on past experience and current trends.

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

A. UGI PNG incurs costs for services provided by UGI Corporation, UGI Utilities, and other affiliated companies, in accordance with affiliated interest arrangements authorized by the Commission. All costs which can be identified as pertaining exclusively to an operating unit are billed directly to that unit. Those costs which 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 PNG 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 PNG, the most recent of which was the Focused Management and Operations Audit of UGI Utilities, Inc., prepared by the PUC's Bureau of Audits, issued in April of 2012, at Docket No. D-2011-2221061 ("Audit Report"). The Audit Report found UGI Corporation's and UGI Utilities' cost allocation methods to be reasonable and appropriate. Audit Report at p. 26. Additionally, in response to a more recent Management Efficiency Investigation of UGI Utilities, UGI CPG and UGI PNG at Docket Nos. D-2015-2473202, D-2015-2473203 and D-2015-2473204, the UGI companies accepted certain recommendations in this area and have implemented them.

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

A. This budget information is the starting point for UGI PNG'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 PNG's FPFTY revenue requirement presentation organized?

A. In Section IV.A, I present a summary of UGI PNG's FPFTY revenue requirement. In Section IV.B, I discuss UGI PNG's proposed rate base. In Section IV.C, I explain the determination of UGI PNG'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 PNG 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 PNG to earn its required overall rate of return of 8.40%. 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 8.40%.

Q. What is the overall requested increase in revenue?

A. The overall requested increase in revenue is $21.661 million. This represents the difference between the *pro forma* FPFTY revenue requirement of $230.229 million and the annual level of operating revenues of $208.568 million under existing rates. These figures are shown on line 10 of Schedule A-1 of UGI PNG Exhibit A (Fully Projected).

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 PNG's Distribution System Improvement Charge ("DSIC"), and other *pro forma* normalizing adjustments. The net effect of these adjustments is shown in UGI PNG Exhibit A (Fully Projected), Schedule D-5, and is discussed in the direct testimony of David E. Lahoff (UGI PNG Statement No. 7).

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

A. UGI PNG's principal accounting exhibit is UGI PNG Exhibit A (Fully Projected), which includes a presentation for the FPFTY ending September 30, 2018. Section D of UGI PNG Exhibit A (Fully Projected) presents UGI PNG'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 and D-6 through D-34. These expense adjustments are used, in part, to derive UGI PNG's *pro forma* income at present and proposed rates as set forth in Schedule D-1.

UGI PNG Exhibits A (Historic) and A (Future) follow the format of UGI PNG Exhibit A (Fully Projected), but reflect data for the appropriate test years ending September 30, 2016 and 2017, respectively. This information is provided in an effort to comply with the Commission's filing requirements and provides a basis for comparing our FPFTY claims with prior results.

1. Summary

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

A. Schedule D-1 presents a summary income statement that includes UGI PNG's claimed gas revenues, expenses, and taxes at present and proposed rate levels. The direct testimony of David E. Lahoff (UGI PNG Statement No. 7) addresses the presentation of *pro forma* revenues, adjustments thereto, and the supporting schedules. Schedule D-1 also shows the proposed revenue increase of $21.661 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 20, this amount is $47.701 million. This represents a $12.513 million increase from the level under current rates ($34.188 million), as shown on line 20 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, 2018. 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 PNG 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 schedules D-5a and D-5b) and D-6 and discussed in the direct testimony of witness David E. Lahoff (UGI PNG Statement No. 7). Regarding *pro forma* expenses, the derivation of the various adjustments are summarized individually on pages 1-2 of Schedule D-3, lines 17-55. The details for these adjustments are found in Schedules D-4 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 PNG Exhibit A (Fully Projected), Section D.

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

A. Yes, it does. UGI PNG budgets its operating expenses both by FERC account and by cost element, such as payroll, employee benefits, rent, etc. UGI PNG 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 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 PNG 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 increase purchased gas cost expense by the same amount of the gas cost revenue adjustment recommended in the direct testimony of David E. Lahoff (UGI PNG Statement No. 7) and as shown on Schedule D-5, column 3, lines 7-12. UGI PNG 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 $1.383 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 that 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 ("S&W") adjustment shown on Schedule D-7.

A. Schedule D-7 shows a $293,000 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 6 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 PNG's budgeting process for the operating expense portion of salaries and wages.

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

A. The two adjustments are designed to enable the Company to fully recover its Environmental remediation expense incurred in connection with its obligations under a Consent Order Agreement with the Pennsylvania Department of Environmental Protection.

Q. Please describe the first of the two MGP 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 to remediate former manufactured gas plant sites in accordance with the Consent Order Agreement

("COA"). This is the amount the Company anticipates it will spend in the FPFTY in accordance with the COA. The annual amount is based on taking a simple average of the last three years of cash expenditures for MGP remediation expense ($1.442 million, less the amount budgeted by the Company ($1.152 million), or $290,000.

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

A. The second adjustment is designed to recover, over a three year amortization period, the difference between the amount of MGP remediation expenditures incurred by PNG under the COA over the period since the future test year ending September 30, 2009 used to establish rates in the Company's most recent general rate proceeding (Docket No. R-2008-2079660) and the amount of such expenditures included for ratemaking purposes over the same period ($8.8 million) at the $1.1 million annual amount agreed upon in the settlement of that case, in accordance with the ratemaking reconciliation mechanism approved by the Commission.

Q. How is the amount to be amortized in the second Environmental Adjustment determined?

A. This calculation is show on Schedule D-8, at lines 7-9. The unrecovered expenditures (line 9) represents the actual difference between (a) costs UGI PNG incurred in accordance with its COA with Pennsylvania Department of Environmental Protection to remediate certain former manufactured gas plant sites since the Companies last base rate case future test year (line 7) and (b) the $1.1 million annual cost level specified in Paragraph 17.v to the Joint Petition for Settlement of All Issues approved by the

Commission in the Company's last rate case (Docket No. R-2008-2079660) times the number of years between the end of the future test year in the last base rate case and the beginning of the fully projected future test year in this case (Line 8).

Pertaining to the reconciliation feature, Paragraph 17.v provides: "PNG's reconciliation mechanism for environmental expense is approved. The initial expense under the reconciliation mechanism will be $1.1 million." Under the reconciliation mechanism, the Company was permitted to accumulate, defer and obtain ratemaking recovery for costs that exceeded the $1.1 million annual level less any cost shortfall in years where actual expenditures fell below the $1.1 million level.

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 $1.442 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 ratepayers (in the case of an overcollection) or recovered from ratepayers (in the case of an undercollection.

Q. Please discuss Schedule D-9, which shows an adjustment for payroll and benefits expense attributed to an assortment of employee related costs.

A. The adjustment for employee additions shown in Schedule D-9 is made up of four separate cost elements for payroll changes that were not factored into the Company's

FPFTY budget. These include: (1) $413,000 of payroll to support 8 incremental positions that are needed in the area of Operations Support; (2) $834,000 of payroll costs representing the effect that re-deployment of employees currently working on the UNITE Project who will resume their former or comparable positions within the utility at the close of the program; (3) $24,000 representing the additional costs associated with changes in the Company recently adopted changes to its incentive compensation structure; and (4) a $5,000 increment representing increased costs associated with implementing the results of a wage banding study that allows the Company to be more competitive for purposes of attracting and retaining certain types of employees. Each of these adjustments represents changes adopted by the Company since the FPFTY budget was completed.

Q. Please identify the benefit that the Company foresees in hiring 8 additional operations support personnel than it budgeted.

A. UGI Utilities' various utility businesses have undergone major changes over the past few years. These include the UNITE project, changing operations practices and procedures, and resizing and reshaping its work force. The benefits to be derived from these changes include increased customer service performance, safer gas operations, and increased operational efficiency and effectiveness. PNG's field operational needs have grown rapidly due to its increased construction and field operations requirements, growth in our service territory, and added regulatory requirements. In particular, the 8 additional employees for gas operations will be performing the following functions:

1. Operations Superintendent (1 position) and Operations Lead (1 position): to improve span of control for Gas Operations in a northern portion of our service territory, which has seen significant increases in the need for field construction and restoration management in connection with our Long Term Infrastructure Improvement Program (LTIIP) and general system growth;
2. Operations Support Services (OSS) Coordinator (2 positions): these administrative positions are needed to provide support to two operations Supervisors so that back office work can be managed more effectively and the operations Supervisors will have additional time to visually supervise field operations;
3. Project Expeditor (2 positions): these positons are designed to support project completion activities so that construction and maintenance projects may be promptly documented and mapped in our mapping system; and
4. Mechanic II (2 positions): these positions are necessary to support emergency response, customer field requirements, and other compliance work, including line locating and capital project inspection in the Tunkhannock area that is being served by one of our larger GET Gas Projects. Tunkhannock is somewhat remote from the closest operations center. As we expand into presently underserved and unserved areas of our service territory, our workforce and the supporting network of operations systems need to be extended into those areas. In some instances, this will require additional payroll and other O&M expenditures in addition to the capital needed to build-out the pipeline infrastructure.

Q. Please explain the basis for the adjustment related to the redeployment of the UNITE personnel.

A. The UNITE project is expected to be completed in the fourth quarter of the FTY. The salaries and benefits of the personnel currently working on the UNITE project that are currently capitalized as a result of their dedication to that project will no longer be capitalized. As those employees are redeployed to their former or other positions in such departments as gas operations, engineering, and customer operations, a larger portion of their payroll and benefits will be expensed. This adjustment represents the difference in annual operating expense that will be recorded after the UNITE program is placed into service and the employees resume their former or new positions**.**

Q. Please discuss the third and fourth adjustments on Schedule D-9 related to incentive compensation and salary banding.

A. The third adjustment is to recognize the incremental expense associated with a recently implemented change to the Company's incentive compensation program. UGI's incentive compensation plan historically did not offer incentive compensation bonuses to managers or other professional positions in certain middle tier position grades. After review, the Company decided to increase the number of positions offered these incentives. To receive a payment under this program, the employees must achieve defined key performance metrics in areas such as workplace or public safety, operating expense, emergency response, or distribution leak metrics.

The fourth adjustment recovers the costs associated with the establishment of new salary bands that were recently adopted after the preparation of the budget. These salary bands were developed to help ensure that employees are paid annual salaries comparable to other positions in the competitive workplace.

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 PNG expects to incur in this case ($821,000). That amount is then normalized over a three-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 $274,000 to reflect a normal annual level of rate case expense. We believe that UGI will make regular rate case filings, going forward, given the significant capital investments it has undertaken in accordance with its PUC-approved Long-Term Infrastructure Improvement Program.

Q. What is the nature of the adjustment being 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 2014 to 2016. 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 1.264% 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 $2.567 million shown in column 4 on line 7. This results in an increase in the level of uncollectible accounts expenses for the FPFTY from the budgeted amount of $2.255 million as shown on line 5. The 1.264% 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. What is shown on Schedule D-13?

A. There are two adjustments shown here. The first adjustment is designed to adjust operating expenses to allow the Company to defer and amortize the one-time costs incurred to transition the Company's headquarters operations from its existing leased space at the Stone Pointe complex to a newly built headquarters building in Lancaster County that will be occupied in the fourth quarter of the FPFTY. The second adjustment is designed to adjust operating expenses currently being incurred at the Company's Stone Pointe headquarter building to annual levels we expect to incur at the new office building.

Q. Why is the Company proposing to relocate its headquarters personnel to a new building?

A. There are a number of reasons. First, the currently leased space at Stone Pointe presents several challenges. These challenges include insufficient space to house all of our headquarters staffing together with complementary staffing currently located elsewhere in the Company's Morgantown Road office building and its Lancaster Service building. The complementary positions include IT, maps and records, and engineering staff who also suffer from space challenges at facilities where they are located. Placing all of those resources together will allow the Company to build a united team within the same centralized location for the purposes of more collaborative alignment of our systems and processes. Aside from the space considerations, the Stone Pointe lease is scheduled to expire in March 2019. While we have an option to extend the lease beyond that date, the current lease provides for a doubling of the annual lease expense for any extension. Finally, the Stone Pointe location suffers from an aging infrastructure that needs upgrading (HVAC, elevators, etc.) and is inconveniently located for employees and visitors alike with few conveniences in the building or nearby. The move from Stone Pointe to the new office building is a good long-term economic and operating decision that will enhance the Company's ability to provide safe and reliable service to its customers.

Q. Are there other adjustments reflected in the filing associated with the new office building?

A. Yes. UGI PNG's rate base claim includes an allocated share of the overall budgeted capital expenditure for the building and underlying land and other land improvements. These expenditures were allocated using the MWF discussed earlier in my testimony.

Q. Please explain the adjustment shown on Schedule D-14.

A. The adjustment shown on Schedule D-14 is designed to reflect an update of estimated pension expense prepare after the budget was finalized. The updated estimate is based on a more recent calculation and reflects the cash to be contributed to the plan in the fully projected future test year. The amounts reflected in the calculation for the pension adjustment include those directly attributable to the UGI PNG pension in addition to the portion of the UGI Corporate and UGI Utilities' pension expense that is included in the expenses allocated to UGI PNG.

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, $1.157 million, is shown on line 5 of Schedule D-15. This amount was compared to the three-year average injuries and damages expenses of $1.942 million calculated on lines 1-4 to arrive at an increase in injuries and damages expense of $785,000 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 PNG'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 removes membership expense that is not allowed to be charged to the customer. Line 10 on Schedule D-15 shows the total adjustment to remove lobbying expenses and other non-allowable expenses in the amount of $12,000. Otherwise, these memberships provide the Company and its customers with operational, customer service, and other service related benefits.

Q. Please explain the adjustment for Licensing of New Software shown on Schedule D-15.

A. Since the budget was developed for 2017, the Company has identified a need for two new software systems to support the business. Both of these systems will be cloud-based and incur annual licensing fees. The first system is a contractor management system for $103,000 per year and the second is a payroll software program for $145,000 per year. This adjustment includes an offsetting adjustment to remove a slightly higher cost payroll system that had been included in the Company's budgets. The new systems are expected to be implemented during the FTY and costs are based on vendor supplied quotes. These reflect the portion of the overall fees that are allocated to UGI PNG

Q. What do the two components of the Distribution Expense Adjustment on Schedule D-15 identified as Tunkhannock Operations Support and Right of Way Clearing Expense represent?

A. This two-part adjustment measures the additional costs associated with two initiatives undertaken since the FPFTY budget was adopted. First, the Tunkhannock Operations Support represents anticipated non-payroll expenditures (fuel, facility, materials) that will be incurred in and around the Tunkhannock area. I discussed the reasons for these incremental costs earlier in my testimony in connection with the additional operations headcount adjustment shown on Schedule D-9. For the purposes of this case, the additional annual non-payroll O&M cost associated with the expansion into Tunkhannock is $96,000.

Second, the Company plans to accelerate its right of way (ROW) clearing cycle in some portions of its service territory to bring all of its service area into one coordinated maintenance cycle. By doing so, the Company will more efficiently perform routine and emergency maintenance in areas of distribution system that are subject to tree and plant growth along its rights of way. The added annual cost of this initiative is $127,000.

Q. Please discuss the adjustment for the program to remediate mechanical tees of $307,400 shown on Schedule D-15, line 17.

A. As discussed in the direct testimony of Company witness Hans G. Bell (UGI PNG Statement No. 10), UGI PNG is planning a 10-year program to identify and remediate the mechanical tees that remain in service. The estimated cost of the 10-year program is $3.074 million or $307,400 per year. This adjustment is shown in Schedule D-15, line 17.

Q. The next adjustment on Schedule D-15 shows a $149,000 cost item for Interest on Customer Deposits at line 18. Please discuss.

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 ($4.975 million) times the required interest rate (3 percent) anticipated for the FPFTY, as published by the Pennsylvania Department of Revenue and required under the Company's tariff.

Q. Please discuss the Management Challenge adjustment of $1.67 million shown on Schedule D-15, line 19?

A. The management challenge adjustment removes a placeholder for potential, unspecified cost reductions that was built into the Company's FPFTY budget. However, at this point, the Company has no plans to implement any cost savings measures that will meaningfully reduce any of the activities reflected in the cost elements included in its operations budgets. This is in part due to the financial demands created by the increased level of operations and maintenance activity throughout the service territory that I have discussed elsewhere in this testimony. Thus, by removing the management challenge reduction, the Company's *pro forma* budget will better reflect the actual operating expenses now anticipated for the FPFTY.

In addition, the Company's cost of operations reflects a multi-year ramp-up in personnel and changed operations practices that have led to the improvements discussed in Mr. Szykman's (UGI PNG Statement No. 1) and Mr. Bell's (UGI Statement No. 10) testimonies. At this point, the Company believes it is moving towards a steady state model with the cost of operations increasing, if at all, at or below the level of wage increases granted to its employees.

Specifically, over the past several years, the Company's enhanced operational focus and growing customer base has led to significant increases to the cost of operations. This was in particular reflected over the 2014-2015 fiscal years, in large part due to substantial growth in our field and operational support workforce. Since then, however, operations costs have substantially levelled to the point where budgeted O&M expense for the FPFTY ($62.033 million, after elimination of management challenge) show an annual growth in O&M expense of only 2.2 percent since the 2015 fiscal year result ($58.154 million), which is substantially less than the average wage and salary increases afforded our employees over the same period of time.

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 Credits, and Pre-Program Arrearages, third party administrator expense, LIURP expense, and administrative costs associated with its C.A.R.E.S. 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 $293,000.

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

A. This adjustment reflects the incremental expense related to the Company's proposed 5-year EE&C Program, which is discussed in the direct testimony of Theodore M. Love (UGI Statement No. 12). The expenses included in this adjustment represent the first year program costs. As the EE&C Program is dependent on receiving authorization from the PUC in this proceeding, it was not included in the FPFTY budget. As shown in Schedule D-19, the total first year EE&C program is $1.730 million. The derivation of this amount is discussed in Mr. Love's direct testimony.

3. Depreciation Expense

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

A. UGI PNG's depreciation study is set forth in UGI PNG Exhibit A (Fully Projected) and shows the determination of *pro forma* depreciation expense. This study uses the FPFTY ending September 30, 2018 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 PNG Exhibit A (Fully Projected), Schedule D-21, and is further explained in the direct testimony of John F. Wiedmayer (UGI PNG Statement No. 6).

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

A. UGI PNG witness Wiedmayer presents the depreciation analysis that serves as the foundation of the depreciation adjustment. The adjustment for depreciation expense of $1.753 million set forth on Schedule D-21, page 2, column 3, 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, ending September 30, 2018. This schedule also shows an increase to the net negative salvage amortization of $739,000. The total annualized depreciation expense for the FPFTY, net of costs charged to clearing accounts and net salvage amortization, is $2.009 million as shown on Schedule D-3, page 2, column 10, line 52.

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 adjustment on line 2 removes the capital stock tax in the amount of $329,000 as the capital stock tax is set to phase out by the end of the HTY. 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 $108,000. The calculation of these adjustments is shown in more detail on Schedule D-32.

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 PNG Statement No. 4). 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. Ms. Walker, are you familiar with Section 1301.1 of the Public Utility Code, which is otherwise known as Act 40 of 2016?

A. Yes, I understand that Act 40 of 2016 was enacted recently. I further understand that 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. My understanding is predicated in part on the advice of counsel.

Q. Has the Company calculated what would have been the level of a consolidated tax savings adjustment for PNG 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. The amount of consolidated tax savings adjustment applicable to UGI PNG would have been $171,000. Applying the gross revenue conversion factor to that amount of tax expense results in a revenue requirement of $292,000.

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 PNG Statement No. 10), UGI PNG's *pro forma* capital additions for reliability or infrastructure projects in the FTY is $128.8 million and for the FPFTY is $66.4 million. This expenditure level is greater than 50% of the amount of what would have been the consolidated tax savings adjustment under prior ratemaking principles.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI PNG STATEMENT NO. 3 – MEGAN MATTERN

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 3

Direct Testimony of
Megan Mattern

Topics Addressed:	**Accounting** **Historic Costs** **Rate Base** **Accounting for Data Preparation Costs for Cloud Based Services**

Dated: January 19, 2017

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. Megan Mattern, 2525 North 12th Street, Reading, Pennsylvania 19612-2677.

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

A. I am employed by UGI Utilities, Inc. ("UGI") and its subsidiaries as Controller and Principal Accounting Officer. UGI is a subsidiary of UGI Corporation ("UGI Corp."). UGI's subsidiaries include two wholly-owned natural gas distribution companies, UGI Central Penn Gas, Inc. ("UGI CPG"), and UGI Penn Natural Gas, Inc. ("UGI PNG" or "the Company), that are 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, UGI PNG, and UGI CPG. My duties currently include accounting, accounts payable, cash remittance and Sarbanes-Oxley ("SOX") functions for all of the utilities in the UGI system 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. What is your educational background?

A. I received a Bachelor's degree in Accounting from King's College in 2003, and a Master's degree in Business Administration from Wilkes College in 2007. Additionally, I have been a Certified Public Accountant since 2009.

Q. Please describe your professional experience.

A. 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, Sarbanes-Oxley controls and oversight, and 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.

Q. What is the purpose of your testimony?

A. I am providing testimony on behalf of UGI PNG. First, I will explain UGI PNG's accounting processes and present the actual book accounting results used in the Company's historic test year ("HTY") (Part II), while the future test year ("FTY") and fully projected future test year ("FPFTY") budgets are discussed in the direct testimony of Kindra S. Walker (UGI PNG Statement No. 2). Second, I will present the Company's claim for rate base for the ("HTY"), FTY, and FPFTY (Part III). Third, I will explain a rate base adjustment for the development of data base assets in connection with the Company's use of cloud-based information services (Part IV).

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

A. Yes, I am sponsoring those portions of UGI PNG Exhibit A (Fully Projected), Exhibit A (Future) and Exhibit A (Historic) addressing rate base and certain adjustments to rate base and operating expenses that I discuss later in my testimony. I am also sponsoring those responses to the Commission's filing requirements and standard data requests where my name is indicated as the sponsoring witness.

II. ACCOUNTING PROCESS AND HISTORIC COSTS

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

A. The accounting records of UGI PNG 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 PNG subject to audit?

A. Yes. The books and records of UGI PNG 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 PNG reflect the original cost value of property?

A. Yes, they do. UGI PNG'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 PNG follow to assure that property reflected in its plant accounts is used and useful?

A. UGI PNG 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 PNG plant property accounts, subject to review by authorized individuals, who must approve the entries. The process employed by UGI PNG is the same as that employed by UGI Gas and UGI CPG, and its integrity has been reviewed 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 PNG's claim in this proceeding. As discussed in the direct testimony of Company witnesses Paul Szykman (UGI PNG Statement No. 1) and Kindra Walker (UGI PNG Statement No. 2), the Company's claim is based on a fully projected future test year period ("FPFTY") ending September 30, 2018. The accounting data for the FPFTY was derived from UGI PNG's operating and capital budgets for the 12 months ending September 30, 2018, as shown in UGI PNG Exhibit A (Fully Projected). The accounting data for the historic test year ("HTY") and future test year ("FTY") was derived from UGI PNG's books and records, and capital and operating budgets. UGI PNG Exhibit A (Future) is based on adjusted budgeted data for the year ending September 30, 2017. UGI PNG Exhibit A (Historic) is based on adjusted experienced data for the year ended September 30, 2016.

III. <u>FULLY PROJECTED FUTURE TEST YEAR RATE BASE</u>

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

A. UGI PNG's rate base presentation is shown in UGI PNG Exhibit A (Fully Projected), Schedule C-1. Schedule C-1 summarizes the UGI PNG 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 4-6 show the amounts at present and proposed rates, respectively. UGI PNG's total FPFTY rate base claim -- net of deductions for accumulated deferred income taxes, customer deposits, and customer advances -- is $555.975 million. 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 PNG determined its FPFTY rate base value for plant in service.

A. UGI PNG's claim for utility plant in service represents the sum of the closing plant balances as of September 30, 2016, and budgeted plant additions for the years ending September 30, 2017 and September 30, 2018, less budgeted FTY and FPFTY plant retirements.

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

A. This schedule includes 9 pages and presents UGI PNG's FPFTY claim of $957.8 million for used and useful gas utility plant in service on page 2, column 2, line 64. Gas utility plant enables UGI PNG to provide safe and reliable gas service to its customers.

Q. How was the gas utility plant in service amount of $957.8 million 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, 2018. The amount includes: (1) utility plant in service as of September 30, 2016 and (2) budgeted capital expenditures expected to close to plant for the 12-month periods ending September 30, 2017 and 2018, less plant retirements during the same period. UGI PNG witness Hans G. Bell, UGI PNG Statement No. 10, discusses the capital addition planning process and the basis for the plant additions in the FTY and FPFTY.

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

A. This information provides a summary of UGI PNG'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 2017 and 2018 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. Please explain the nature of the adjustments in column 4 on schedule C-2, page 5 pertaining to General Plant.

A. For budgeting purposes, the cost of General Plant such as buildings and land, and information systems, is recorded on the records of the legal owner of the plant. In some cases, that legal owner is UGI Utilities and in other cases, UGI PNG. However, the plant owned by UGI Utilities is used for the common benefit of UGI Electric, UGI Utilities, UGI PNG and UGI CPG and their respective customers and therefore is treated as common plant for ratemaking purposes. Because of this common benefit, a portion of the cost of the common plant owned by UGI Utilities is allocated to UGI PNG and other UGI subsidiaries that benefit from the plant and, in instances where UGI PNG owns the plant, a portion of the costs are allocated from UGI PNG to other utilities benefiting from its use. The adjustments in Column 4 of Schedule C-2, page 5 for General Plant represent, in part, the net result of these allocations.

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 2012 through 2016, 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 PNG determined its rate base value for accumulated depreciation.

A. UGI PNG started with accumulated depreciation as of September 30, 2016, 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. W~~e~~iedmayer (UGI PNG Statement No. 6), with the underlying FPFTY depreciation analysis provided in UGI PNG Exhibit A (Fully Projected).

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

A. UGI PNG's accumulated depreciation claim is shown on Schedule C-3 of UGI PNG Exhibit A (Fully Projected). This schedule, containing 11 pages, presents the accumulated provision for depreciation as of September 30, 2018, distributed among the various FERC accounts. The total amount for accumulated depreciation, $295.124 million, 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 2017 and 2018 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 affiliated companies. 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 PNG 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 PNG'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 PNG'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 17.64 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 $6.457 million. The average daily expense balance of $366,000 shown on line 9 is determined by dividing the total *pro forma* annual operating expenses, excluding uncollectible accounts expense of $133.587 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, 2016 (line 17, column 2). This results in an accounts receivable turnover rate of 12.77 (line 19, column 4), which is equivalent to 28.58 lag days (line 20, column 5) (365 divided by 12.77 accounts receivable turnover rate). As shown on lines 20-23, the payment portion of the revenue lag is added to (1) the 2.70 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 46.49 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 2015 through September 2016. The total dollar amount of gas purchased during this period was $66.862 million, and the average payment lag equaled 31.38 days. The payment lag was determined using the midpoint of the service payment 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 14, 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 four 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 1-8, 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. After these adjustments, the average of the expense lag days for each month shown on Schedule C-4, page 5, column 4, line 9 resulted in a payment lag for general disbursements of 33.88 days. The 33.88 day lag for Other Disbursements is then brought forward to Schedule C-4, page 4, line 14 and 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 $32,000 shown on line 5. That amount is then multiplied by the net payment lag, resulting in a reduction to the working capital allowance of $1.421 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 2015 through September 2016.

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

A. UGI PNG's claim for CWC is $7.404 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 PNG contracts for capacity. As is typical for most natural gas distribution systems, UGI PNG purchases storage gas throughout the year for use primarily during the winter heating season. UGI PNG's claim for gas storage inventory is based on a 13-month average book value for the period ending September 2018 as shown on Schedule C-5. The average monthly gas inventory balance for the FPFTY is $4.729 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)

Q. Please explain how the rate base value for ADIT was calculated.

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

6. Customer Deposits

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

A. Customer deposits offset the need for UGI PNG to provide capital. UGI PNG's claim for customer deposits is based on the September 30, 2016 month-end balance as shown on Schedule C-7. Act 155 of 2014 became effective December 22, 2014, and no longer permits the Company to collect deposits for customers who qualify for low income programs. As a result, the Company's customer deposits balance has declined and now leveled off at a balance representative of future operations. For this reason, the balance at the end of the HTY was used to determine the rate base offset for customer deposits.

Q. What is the rate base offset for customer deposits?

A. The customer deposit offset is $4.975 million as shown on Schedule C-1, line 7 and on Schedule A-1, line 7.

7. Materials and Supplies Inventory

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

A. UGI PNG maintains various materials and supplies in inventory for use in its operations. Its claim for those items is $4.621 million, as shown on Schedule C-1, line 8. 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.

Q. Why is the HTY balance an appropriate measure of materials and supplies for the FPFTY?

A. The balance at the end of the HTY is appropriate for two reasons. First, as a result of the 2011 Management Audit, the Company accepted the Commission's audit staff recommendation that UGI PNG increase its levels of emergency stock. Second, the Company's increasing capital expenditure plans have increased the need to stock longer lead time items, such as certain sizes of pipe, to ensure these items are available when needed. These two factors have contributed to an increasing amount of materials and supplies inventory, which is reflected by the use of the HTY-end balance for this claim. UGI PNG will update this balance during the course of this proceeding.

IV. <u>ACCOUNTING TREATMENT OF DATA PREPARATION COST</u>

Q. Ms. Mattern, what is the $563,400 adjustment to rate base included in schedule C-2, page 5, line 54 for data preparation costs?

A. This adjustment proposes to capitalize certain costs incurred to develop data base assets in connection with the Company's use of cloud-based information services. Under GAAP, such costs are ordinarily accounted for as operating expenses. In this case, however, the Company is requesting Commission approval to record these costs as a long-lived capital asset.

Q. Please describe these costs.

A. These costs are incurred as payments to outside vendors with whom the Company will contract to create data bases that are used in connection with long-term, cloud based services that the Company will begin to receive under a licensing agreement during the FTY and the FPFTY. As identified in the direct testimony of Kindra Walker (UGI PNG Statement No. 2) in connection with her adjustment for Licensing Fees for New Software at Schedule D-15, the cloud based service claimed in this case is for payroll management services. The Company anticipates that the License will have a period of 5 years, with the right for UGI PNG to extend the length of the license for the service.

Q. Why does the Company believe that the costs incurred to prepare the data bases for cloud based services should be capitalized?

A. Under the current GAAP accounting guidelines, the costs incurred to prepare data bases for on premise software is required to be capitalized, while the costs to prepare data bases for cloud basis services are considered expenses. Cloud based services offer many advantages to traditional on premise software such as enhanced security, reliability, and flexibility. The data bases created for the cloud-based services are used by the Company to optimize various aspects of the utility service provided to its customers over, at a minimum, the life of the cloud based service agreement. Moreover, the Company retains ownership and control of these data bases after the close of the cloud based service for which they are being created and likely will use the information in subsequent applications. Accordingly, as the data bases provide benefits to customers over extended periods of time and not just the period in which the costs are incurred, the Company believes that the costs should be capitalized and depreciated over the life that the data bases will remain used and useful.

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

A. No. As the underlying outside service is needed to develop the data base was not included in our budget, there is no associated reduction to O&M expense necessary.

Q. Does this conclude your direct testimony?

A. Yes, it does.

UGI PNG STATEMENT NO. 4 – PAUL R. MOUL

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 4

Direct Testimony

of

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

Topics Addressed:	**Cost of Common Equity**
	Rate of Return

Dated: January 19, 2017

UGI Penn Natural Gas Company
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
FOMC	Federal Open Market Committee
g	Growth rate
IGF	Internally Generated Funds
IRPA	Interest Rate Protection Agreement
Lev	Leverage modification
LDC	Local Distribution Companies
LIBOR	London Interbank Offered Rate
LT	Long Term
M&A	Merger and Acquisition
P-E	Price-earnings
PNG	UGI Penn Natural Gas Inc.
PPUC	Pennsylvania Public Utility Commission
r	represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a
s x v	Represents external growth

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
S&P	Standard & Poor's
UGIU	UGI Utilities, Inc.
UGI	UGI Corporation
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value

DIRECT TESTIMONY OF PAUL R. MOUL

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in 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 that UGI Penn Natural Gas, Inc. ("PNG") should be authorized as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in UGI PNG 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 a rate of return on common equity of 11.20%, which is within the range of results of the cost of equity models and includes 0.20% in recognition of the strong performance of the Company's management in the areas of customer service and management effectiveness. My 11.20% cost of equity recommendation is established using capital market and financial data relied upon by investors when assessing the relative risk, and hence cost of capital for the Company. My 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. As shown on page 1 of Schedule 1, I have presented the 8.40% weighted average cost of capital for the Company, which is calculated with the September 30, 2018 fully forecast test year end capital structure ratios for its parent company, UGI Utilities, Inc. ("UGIU"). The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

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

A. UGIU owns PNG and its affiliated gas utility, UGI Central Penn Gas, Inc. ("CPG"). UGIU is itself a wholly-owned subsidiary of UGI Corporation ("UGI"). As now constituted, the natural gas distribution operations of UGIU and its subsidiaries provide service to approximately 626,000 customers in 44 eastern and central Pennsylvania counties. UGIU also provides electric delivery service to approximately 62,000 customers in portions of Luzerne and Wyoming Counties.

The Company provides natural gas distribution service to 166,513 customers in thirteen northeastern Pennsylvania counties. The throughput on PNG's system is significantly influenced by sales to its heating customers, as heating degree days in northeastern Pennsylvania are very weather sensitive. Throughput to on-system customers in 2015 was represented by approximately 29% to residential customers, approximately 22% to commercial customers, and approximately 49% to industrial customers. Also, a meaningful proportion of the Company's throughput is represented by transportation to commercial and industrial customers. Total transportation to all customers represents approximately 63% of total throughput. The Company obtains its natural gas primarily from Appalachian suppliers through delivery arrangements with three interstate pipelines and local gathering systems. The Company supplements its flowing natural gas with gas withdrawn from storage.

The Company's service territory contains industries involved in paper products, manufacturing, food processing for both human consumption and for animals, pharmaceuticals, health care providers, and electric generation. This sales profile signifies high risk for the Company. The significant portion of the Company's throughput to industrial customers makes the Company a higher risk utility as compared to the proxy group of companies that I will describe below. In addition, space heating use represents 37% of throughput and 91% of the customer count. With an absence of a revenue stabilization feature in its tariff to account for variations in weather, this makes the Company a more risky enterprise as compared to most other gas distribution utilities. In the case of the proxy group, six of the companies operate with revenue decoupling mechanisms ("RDM") that deal with revenue variations in usage caused by weather. And one of the remaining companies has a weather mitigated rate design that recovers it fixed costs more evenly during the heating season. This leaves only one company in the proxy group without a RDM or weather mitigated tariff.

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 11.20% represents a reasonable cost of equity, which is within the range of results of the cost of equity models and reflects 0.20% to recognize the strong performance of the management of PNG in the areas of customer service and management effectiveness.

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

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

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

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed for my proxy group of eight (8) natural gas companies. The proxy group consists of natural gas companies that: (i) are engaged in the natural gas distribution business, (ii) have publicly-traded common stock, (iii) are contained in The Value Line Investment Survey, and (iv) are not currently the target of an announced merger or acquisition. From the natural gas utilities covered by the basic service of Value Line, I excluded two companies. The eliminations were: NiSource Inc. due to its sizable electric operations and UGI Corp. due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. The remaining eight companies are included in my Gas Group. I should note that there has

[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).

been some recent speculation on the internet regarding the potential acquisition of WGL Holdings by a foreign utility. However, there is no firm acquisition agreement in this regard, nor did these rumors exist during the period when I measured the stock prices of WGL Holdings. The companies in the proxy group are identified on page 2 of Schedule 3. I will refer to these companies as the “Gas Group” throughout my testimony.

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.

DCF		10.03%
Risk Premium		11.50%
CAPM		11.17%
Comparable Earnings		11.20%

From these measures, I recommend a cost of equity of 11.20%, which is within the range of results reflected in the above table and also reflects the above-referenced 0.20% for strong management performance. My recommendation is on the conservative side for PNG because it is based on the Gas Group that does not have the Company's high risk attributes as explained in the testimony of Mr. Paul Szykman and Mr. Robert Stoyko.

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 that this will put an additional strain on performance in the short run. In recognition of its performance, the Company should be granted an opportunity to earn an 11.20% rate of return on common equity. Such return will help promote natural gas usage in Pennsylvania and its associated positive economic and environmental effects. I note that my recommendation does not reflect any adjustment for the greater risk faced by PNG due to its higher risk traits.

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, the expansion of shale gas induced price benefits and issues, 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 their marketing activities. This situation is unlike that of PNG, where specific thresholds must be satisfied for system expansions, and where promotional activities are constrained. The Company also faces the risk associated with throughput to interruptible customers whose deliveries are influenced by global oil prices. Moreover, the Company's close proximity to the Marcellus shale production area provides customers with the opportunity to bypass the Company's distribution 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 industrial customers. Industrial customers represent approximately 49% of throughput, but these customers represent only 0.1% of total customers. Moreover, the Company's top twenty-two customers represent 62% of total throughput. Electric generation, manufacturing, paper products, and food processing are among these customers. Paper products face challenges from international competition and fluctuating demand for their 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 (i) the business cycle, (ii) the price of alternative energy sources, and (iii) pressures from alternative providers, such as producers in the Marcellus shale production area. 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 14% of its distribution mains constructed of unprotected steel and cast iron pipe as of year-end 2015. The Company also has approximately 12% 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 $224.5 million. During the 2017-2019 period, gross construction expenditures will represent an approximate 43% increase ($224.5 million ÷ $517.8 million) in net utility plant, including construction work in progress, from the level at September 30, 2016.

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

A. The Commission should recognize the issues listed above when deciding the rate of return issue in this case. In particular, the Company has high risks associated with its significant throughput to industrial customers, proximity to the Marcellus shale production area, and lack of a weather stabilization feature in its tariff. Another important risk is declining usage per customer discussed in the testimony of Company witness Mr. Szykman (PNG Statement No. 1).

FUNDAMENTAL RISK ANALYSIS

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

A. Yes. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors which bear upon investors' assessment of overall risk. The qualitative factors that bear upon the Company’s risk have already been discussed. The quantitative risk analysis follows. For this purpose, I have compared UGI Utilities to the S&P Public Utilities, an industry-wide proxy consisting of all types of public utility endeavors, and the Gas Group. In this analysis, I have used UGIU on a consolidated basis for two reasons. First, the results of PNG form a significant part of the UGIU consolidated financial statements and, along with the results of UGIU’s other natural gas distribution utilities, UGI Gas and CPG, contribute more than 90 percent to UGIU’s operating income and balance sheet assets. Second, the UGIU consolidated capital structure is used to compute the weighted average cost of capital for PNG in this case. Hence, the relevant comparison to the Gas Group are the consolidated results of UGIU.

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 obtained from the <u>Value Line</u> publication consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corp., New Jersey Resources Corp., Northwest Natural Gas, South Jersey Industries, Inc., Southwest Gas Corp., Spire Inc. and WGL Holdings, Inc.

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 minus 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. 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 the Company, UGIU, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedule 2, 3 and 4. The data cover the five-year period 2011-2015. I will highlight the important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, UGIU is smaller than the average size of the Gas Group. Each of 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 UGIU and the Gas Group as compared to S&P Public Utilities and for UGIU as compared to 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 UGIU's stock is not traded, there are no market ratios for the Company. The five-year average price-earnings multiple was similar for the Gas Group and the S&P Public Utilities. The five-year average dividend yields were somewhat lower for

[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).

the Gas Group as compared to the S&P Public Utilities. The average market-to-book ratios were somewhat higher for the Gas Group than the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a 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 56.0% for UGIU, 57.0% for the Gas Group, and 45.1% for the S&P Public Utilities. This shows that the financial risk of UGIU was fairly comparable to that of the Gas Group.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relative levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficient of variation, the greater degree of variability. During the five-year period, the coefficients of variation were 0.096 (1.3% ÷ 13.6%) for UGIU, 0.049 (0.5% ÷ 10.3%) for the Gas Group, and 0.063 (0.6% ÷ 9.5%) for the S&P Public Utilities. These comparisons show higher earnings variability for the Company compared to the Gas Group and the S&P Public Utilities. This signifies higher risk for UGIU compared to the Gas Group.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation and taxes other than income).[3] The five-year average operating ratios were 79.1% for UGIU, 87.7% for the Gas Group,

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

and 80.5% for the S&P Public Utilities. The lower average operating ratio for UGIU suggests somewhat lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. The five-year average pre-tax interest coverage (excluding AFUDC) was 5.39 times for UGIU, 4.94 times for the Gas Group, and 3.18 times for the S&P Public Utilities. The somewhat higher interest coverage for UGIU suggests slightly lower credit risk.

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

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 94.1% for UGIU, 79.3% for the Gas Group, and 81.0% 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 attributed to higher future interest rates, which adds risk for a company with a large construction program.

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 .73 as the average for the Gas Group provided on page 2 of Schedule 3 and .75 as the average for the S&P Public Utilities provided on page 3 of Schedule 4.

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

A. The investment risk of UGIU parallels that of the Gas Group in certain respects. In certain regards, principally related to its small size, significant throughput to industrial customers, lack of a weather stabilization ratemaking mechanism in its tariff, and more variable earned returns, UGIU has somewhat higher risk traits. UGIU has lower risk as shown by its lower operating ratio and higher interest coverages. The financial risk of UGIU is comparable to the Gas Group. The IGF to construction for UGIU 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 tend to understate the Company's cost of equity for this case.

RECOMMENDED CAPITAL STRUCTURE RATIOS

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

A. In the situation where the operating public utility raises its own long-term debt directly in the capital markets, as is the case for UGIU, it is proper to employ the capital structure ratios and senior capital cost rates of the regulated public utility for rate of return purposes. In that case, the property and earnings of the operating public utility forms the basis of the capital employed and the capital cost rates are directly identifiable. Since the PNG does not obtain its capital independently, I have employed the

[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.

consolidated capital structure ratios of UGIU to calculate the rate of return for this case. Not only does UGIU attract investor-provided capital for PNG, it also does that for its gas and electric divisions, and UGI Central Penn Gas, Inc. The circumstances of UGIU indicate that its capital structure ratios should be used for rate of return purposes for each of its utility divisions and both its subsidiaries.

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

A. Yes. Schedule 5 presents UGIU capitalization and related capital structure at September 30, 2016, the end of the historic test year. Also, shown on Schedule 5 is the UGIU capital structure estimated at September 30, 2017, the end of the future test year, and at September 30, 2018, the end of the fully forecast test year. The changes in the Company's capital structure consist of: (i) one maturity of $20 million in the future test year (ii) two maturities of $40 million in the fully forecast test year, (iii) the issuance of $100 million of long-term debt in the future test year, (iv) the issuance of $100 million of long-term debt in the fully forecast test year, and (v) the Company's projection of retained earnings at the end of the future and fully forecast test years.

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

A. Yes. But, I have adjusted the 12-month average balances of short-term debt for the amounts attributable to financing construction work in progress ("CWIP"). I have done so 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 are removed from the capital structure for rate case purposes. The Commission typically views short-term debt on a twelve-month average basis as a source of financing that LDCs use to carry stored gas inventory. For the purpose of calculating the short-term debt ratio, I have used a twelve-month average for ratesetting purposes. My approach conforms to the seasonal nature of short-term debt related to stored gas inventory, except that it removes short-term debt that is CWIP related. My approach in this case accommodates Commission practice of considering short-term debt for LDCs.

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 Company's capital structure ratios at the end of the fully forecast test year of 41.68% long-term debt, 2.51% short-term debt, and 55.82% 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.

EMBEDDED COST OF DEBT

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

A. Consistency requires that the embedded senior capital cost rates of UGIU must be used for developing a fair rate of return. It is essential that the cost rate of long-term debt is related to the same proportion of senior capital employed to arrive at the capital structure ratios. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of long-term debt at September 30, 2016. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of long-term debt at September 30, 2017. And on page 3 of Schedule 6, the embedded cost of long-term debt is shown for the fully forecast test year. 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 5.00% forecast embedded long-term debt cost rate at September 30, 2018, 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 41.68% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. The cost of short-term debt for UGIU is comprised of two components. It consists of: (i) London Interbank Offered Rate ("LIBOR") and (ii) a margin or spread to recognize the risk associated with UGIU's credit quality. For this case, I have used the Blue Chip Financial Forecasts that shows a forecast LIBOR rate of 2.1% for 2018. For the spread associated with UGIU's credit quality, the margin charged to UGIU is 0.875%. In total, the cost of short-term debt is 2.975% (2.1% + 0.875%) reflecting the two components identified above.

COST OF EQUITY – GENERAL APPROACH

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

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among UGIU, 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 arrived at a cost of equity of 11.20% for the Company, which includes 0.20% in recognition of the exemplary performance of the Company's management.

DISCOUNTED CASH FLOW

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 10.03%.

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 October 2016, 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 date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended October 2016 the average dividend yield was 2.88% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 2.77% and 2.87%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 2.77% for the Gas Group.

[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.

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 for the Gas Group. 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 basis points to the six-month average historical yield, thus producing the 2.86% adjusted dividend yield for the Gas Group.

Q. What factors influence investors' growth expectations?

A. As noted previously, investors are interested principally in the dividend yield and future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent 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 stabilizes 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.

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. Did you consider company-specific data in your growth rate analysis?

A. Yes. As presented on Schedule 8 and Schedule 9, 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.

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.

Schedule 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical growth of earnings per share was in the range of 4.25% to 5.38% for the Gas Group.

Q. Did you also consider analysts' expectations of expected growth?

A. Yes. Schedule 9 provides projected earnings per share growth rates taken from analysts' five year forecasts compiled by IBES/First Call, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, 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, 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, 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.

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 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 5.57% by IBES/First Call, 6.33% by Zacks, 6.73% by Morningstar, 6.11% by SNL and 5.69%% by Value Line. 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, 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, 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 5.57% to 6.73%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 6.25% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. The improved economic growth argues for a higher DCF growth rate. Moreover, for natural gas distribution utilities, additional emphasis on infrastructure rehabilitation suggests that growth will be near the top of the range.

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 31.77% long-term debt, 0.09% preferred stock, and 68.14% common equity, as shown on

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

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 7.86% 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. In this regard, according to the Barron's issue of December 12, 2016, the major market indices' market-to-book ratios are well above unity. The Dow Jones

Utility index traded at a multiple of 1.87 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 3.94 times book value, and the Dow Jones Industrial index was at 3.41 times book value. 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 7.86%, 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 2.16% compensation for having a 44.46% debt ratio, plus 0.01% for having a 0.16% preferred stock ratio. The sum of the parts is 10.03% (7.86% + 2.16% + 0.01%) 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 2.86% dividend yield, the 6.25% growth rate, and the 0.92% for the leverage adjustment in order to arrive at the same 10.03% (2.86% + 6.25% + 0.92%) return. I know of no means to mathematically solve for the 0.92% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.92% adjustment is merely a convenient way to compare the 10.03% return computed directly with the Modigliani & Miller formulas to the 9.11% 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 9.11% return assigned to anything other than the market value of equity cannot equate to a reasonable return on book value that has higher financial risk. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. What does your DCF analysis show?

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 rate setting process rather than the market value equity ratio related to the price of stock.

	D_1/P_0	+	g	+	lev.	=	k
Gas Group	2.86%	+	6.25%	+	0.92%	=	10.03%

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. In the current environment of rising interest rates, the DCF method tends to be less responsive (i.e., there is a lag) to changes in those rates. As such, other methods for measuring the cost of equity, e.g. Risk Premium and CAPM, should be emphasized because they respond promptly to change in interest rates.

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, 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 October 2016, the average monthly yield on Moody's index of A-rated public utility bonds was 3.97%. For the six and three-month periods ended October 2016, the yields were 3.72% and 3.67%, respectively. During the twelve-months ended October 2016, the range of the yields on A-rated public utility bonds was 3.57% to 4.40%. 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 1.37% on a twelve-month average basis, 1.31% on a six-month average basis, and 1.30% on a three-month average basis. From these averages, 1.25% represents a conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

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

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. 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, 2016, 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:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2016	Fourth	3.8%	4.7%	2.8%	1.25%	4.05%
2017	First	4.0%	4.9%	3.0%	1.25%	4.25%
2017	Second	4.1%	5.1%	3.1%	1.25%	4.35%
2017	Third	4.2%	5.2%	3.2%	1.25%	4.45%
2017	Fourth	4.4%	5.3%	3.3%	1.25%	4.55%
2018	First	4.5%	5.5%	3.4%	1.25%	4.65%

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, 2016 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
2018-2022	5.3%	6.3%	4.2%
2023-2027	5.5%	6.4%	4.5%

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.

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

A. To develop an appropriate equity risk premium, I analyzed the results from 2016 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		7.12%
Average Across All Interest Rates		5.65%
High Interest Rates		4.18%

Based on my analysis of the historical data, the equity risk premium was 7.12% when the marginal cost of long-term government bonds was low (i.e., 2.97%, 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 5.65% when the average government bond yield was 5.09%. 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 7.12% premium related to periods of low interest rates and the 5.65% 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	5.00%	+	6.50%	=	11.50%

Indeed, in an environment of rising interest rates, the Risk Premium model provides a direct reflection of the cost of equity that captures higher interest rates.

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 11.17%. 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 0.73 for the Gas Group.

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

A. I used the Value Line betas as a foundation for the leverage adjusted betas that I used in the CAPM. The 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 releveraged 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 0.56 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 0.85 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 0.85 for the Gas Group.

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

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended October 2016, the average yield on 30-year Treasury bonds was 2.60%. For the six- and three-months ended October 2016, the yields on 30-year Treasury bonds were 2.40% and 2.37%, respectively. During the twelve-months ended October 2016, the range of the yields on 30-year Treasury bonds was 2.23% to 3.03%. The low yields that existed during recent periods can be traced to

[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.

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"). Essentially, 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 has ended its bond purchasing program. And, 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 Fed Funds rate by one-quarter percentage point. The FOMC also used this occasion to express a more aggressive approach to future increase in interest rates. FOMC officials indicated that there could be three more one-quarter percentage point increases in interest rates in 2017. This buttresses the prospect that future increases in the federal funds rate will likely occur.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on December 1, 2016 indicate that the yields on long-term Treasury bonds are expected to be in the range of 2.8% to 3.4% during the next six quarters. The longer-term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.2% from 2018 through 2022 and 4.5% from 2023 to 2027. 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. Indeed, the December 1, 2016 Blue Chip indicates that the yield on 30-year Treasury bonds will be 3.8% in 2018.

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 Value Line and S&P 500 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 2.97% 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 4.03% (2.97% + 5.09% = 8.06% ÷ 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 7.93% (11.96% - 4.03%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated a 10.98% total market return from the Value Line data and a DCF return of 10.83% for the S&P 500. With the average forecast return of 10.91% (10.98% + 10.83% = 21.81% ÷ 2), I calculated a market premium of 7.16% (10.91% - 3.75%) using forecast data. The market premium applicable to the CAPM derived from these sources equals 7.55% (7.16% + 7.93% = 15.09% ÷ 2).

Q. Are adjustments to the CAPM 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.[7] 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) were in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,520 million. The mid-cap adjustment of 1.00%, as revealed on page 3 of Schedule 13, would be warranted at a minimum.

Q. What does your CAPM analysis show?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.85 for the Gas Group, the 7.55% market premium, and the 1.00% size adjustment, the following result is indicated.

	Rf	**+**	***ß***	***x (***	***Rm-Rf***	***) +***	***size***	**=**	***k***
Gas Group	3.75%	+	0.85	x (	7.55%	) +	1.00%	=	11.17%

COMPARABLE EARNINGS APPROACH

Q. What is the Comparable Earnings approach?

A. The Comparable Earnings approach estimates a fair return on equity by comparing returns realized by non-regulated companies to returns that a public utility with similar 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

[7] See Fundamentals of Financial Management, Fifth Edition, at 623.

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 11.3% 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 11.1% also using values less than 20%, as provided on page 2 of Schedule 15. Using the average of these data my Comparable Earnings result is 11.20%, as shown on page 2 of Schedule 1.

CONCLUSION

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 11.20% for PNG, which includes 0.20% in recognition of the Company's strong performance by its management in the areas of customer service and management effectiveness. My cost of equity recommendation is obtained from a range of results (i.e., 10.03% to 11.25%) and should be considered in the context of the Company's risk characteristics, as well as the general condition of the capital markets, and the strong performance of the Company's management. 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.

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

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 PNG STATEMENT NO. 5 – PAUL R. HERBERT

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 5

Direct Testimony of
Paul R. Herbert

Topics Addressed: **Cost of Service Allocation**

Date: January 19, 2017

BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION
DOCKET NO. R-2016-2580030

RE: UGI PENN NATURAL GAS, INC.

DIRECT TESTIMONY OF PAUL R. HERBERT

Line
No.

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 President. My duties and responsibilities include the preparation of accounting and financial data for revenue requirement and cash working capital claims, 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 my current position as President.

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 Penn Natural Gas, Inc. ("UGI PNG" or the "Company"). I will explain the cost of service allocation study

COST OF SERVICE ALLOCATION STUDY

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. I have prepared two cost of service studies, which I will describe later, as well as summary schedules that present a simple average of the two studies. The studies provide a basis for determining the extent to which the revenues to be derived from each classification are commensurate with the cost of serving that classification.

Q. Have you prepared a cost of service study for UGI PNG in a prior case?

A. Yes. I prepared the cost of service study in the UGI PNG rate case at Docket No. R-2008-2079660. I also prepared the cost of service study for UGI Utilities, Inc. - Gas Division 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 PNG Exhibit D and in the text, "Gas Rate Fundamentals", published by the American Gas Association's Rate Committee.

Q. Please describe the difference in the two cost of service studies presented for this proceeding.

A. The first study presented in UGI PNG Exhibit D, allocates mains investment to the interruptible class on the basis of average daily volumes (excluding excess capacity). The second study presented in UGI PNG Exhibit D-1, does not allocate any mains investment to the interruptible class. UGI PNG Exhibit D-2 presents the simple average of the two studies in the summary Schedule A-2 as well as the rate of return schedules under present and proposed rates in Schedules B-2 and C-2, respectively.

Q. Please describe UGI PNG Exhibit D.

A. UGI PNG Exhibit D titled, "Cost of Service Allocation Study as of September 30, 2018," is the first cost of service allocation study prepared for UGI-PNG 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, 2018 (“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 PNG 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), 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 PGC volumes for Rate R and Rate N customers.

The costs related to distribution mains were first directly assigned to XD-Firm customers based on an analysis of the mains and the proportion thereof serving each individual XD customer. The methods and procedures used to determine the portion of mains directly assigned to 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 LFD and large IS customers not connected to small mains could be excluded for the small mains allocation. However, the Company did not have sufficient information to readily determine the size of main that each LFD or IS customer is connected. Therefore, the allocation of small and large distribution mains is the same -- allocated to the Rate R, N, DS, and LFD classes based on the average and extra capacity demand for each classification and the average day demand for the Interruptible class.

Customers under Rate XD were excluded from the allocation of small and large distribution mains since 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, after a direct assignment to each of the XD customers, based on the cost of service lines by size and the number of customers in each class. Costs related to meters in Account 381 and the associated house regulators were allocated to the R, N, DS, and Interruptible service classifications, after a direct assignment to each of the XD customers, on the basis of the cost of meters for each class and the number of customers. Costs related to industrial measuring and regulating in Account 385, after a direct assignment to XD customers, were allocated to the LFD and Interruptible Service classes based on the cost of measuring and regulating equipment assigned to each class.

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 Szykman (UGI PNG Statement No. 1) and the direct testimony David Lahoff (UGI PNG Statement No. 7) 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 PNG Exhibit D.

Q. **Please explain the analysis of customer costs as set forth in UGI PNG 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 PNG 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 XD Service?

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

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

A. The costs related to LFD and 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 second cost of service study in UGI PNG Exhibit D-1.

A. The second cost of service study presented in UGI PNG Exhibit D-1 is the same as the first study except for the allocation of mains investment. The second study does not allocate any mains investment to the interruptible class. As a result of this change in allocation of mains investment, composite allocation factors also change.

Q. What is the rationale for not allocating any mains investment to the interruptible class?

A. The rationale for not allocating mains investment to interruptible customers is based on the cost allocation premise that costs should be allocated based on the design of the system facilities. The distribution system was designed to meet peak day requirements for firm customers only. Interruptible customers would have no usage on the design peak day as their volumes would be curtailed. The Company's investment in mains would be the same whether or not there were interruptible customers on the system. Therefore, allocating all mains investment to firm customers is reasonable.

Q. Please summarize the results of the second cost of service study.

A. The results of the second cost of service allocation (UGI PNG Exhibit D-1) set forth in Schedule E-1 are brought forward and summarized in Schedule D-1. The total cost of service by classification in Schedule D-1 is then brought forward to Schedule A-1 (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-1. Schedule B-1 and Schedule C-1 present the rate of return by classification under present rates and proposed rates, respectively.

Q. Please explain UGI PNG Exhibit D-2.

A. UGI PNG Exhibit D-2 presents the simple average of the cost allocation studies from Exhibits D and D-1. Exhibit D-2 sets forth the summary of the average cost or service by classification in Schedule A-2 (columns 2 and 3) compared to revenues under present and proposed rates, as well as the rate of return based on the average cost of service allocation under present rates in Schedule B-2 and under proposed rates in Schedule C-2.

Q. Does that conclude your direct testimony?

A. Yes, it does.

LIST OF CASES IN WHICH PAUL R. HERBERT 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	PSC of W. Va.	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	Revenue Requirements and Rate Design
13.	1995	Pa. PUC	R-953379	Carnegie Natural Gas Company	Revenue 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	PSC of W.Va.	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. Corp	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.CorpCm	PUE-2002-00375	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.CorpCm	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

LIST OF CASES IN WHICH PAUL R. HERBERT TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
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
55.	2007	Oh. PUC	07-1112-WS-AIR	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 Requirements, 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	VaStCorpCom	Pue-2008-00009	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 Corp. Com.	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	VaStCorpCom	PUC-00059	Aqua Virginia, Inc.	Cost Allocation (only)
81.	2009	Mo PSC	WR-2010-0131	Missouri American Water Company	Cost Allocation and Rate Design
82.	2010	VaStCorpCom	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-	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 Rg Ath	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

LIST OF CASES IN WHICH PAUL R. HERBERT TESTIFIED

	Year	Jurisdiction	Docket No.	Client/Utility	Subject
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	Va St Com	2011-00099	Aqua Virginia, Inc.	Cost Allocation
105.	2011	Va St Com	2011-00127	Virginia American Water Company	Cost Allocation and Rate Design
106.	2012	Tn RegAuth	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
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	Va St Com	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

UGI PNG STATEMENT NO. 6 – JOHN W. WIEDMAYER

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2016-2580030

UGI Penn Natural Gas, Inc.

Statement No. 6

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

Topics Addressed: **Depreciation**

Date: January 19, 2017

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DIRECT TESTIMONY OF

JOHN F. WIEDMAYER

DOCKET NO. R-2015-2518438

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 Bachelor of Arts 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 30 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 Energy, Maritime Electric, Nolin Rural Electric Cooperative, AmerenCIPS, AmerenCILCO, AmerenIP, ComEd, Con Edison Company of New York, Orange and Rockland, Rockland Electric (RECO), Baltimore Gas and Electric Company (BGE), Exelon Generation 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 New Jersey Board of Public Utilities and the Pennsylvania Public Utility Commission ("PA PUC" or the "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" and "Data Requirements for a Depreciation Study." I am a member of the Society of Depreciation faculty and have been since 1999 responsible for preparing and presenting courses on depreciation matters each year at the Society's annual conference.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the gas plant of UGI Penn Natural Gas, Inc. ("UGI PNG" or the "Company"). I have been retained by the Company as a depreciation consultant. UGI PNG retained me to determine the book depreciation reserve as of September 30, 2018, to determine the annual depreciation expense to be included as an element of the cost of service, and to testify in support of those two determinations in this proceeding.

I am also a sponsoring witness for UGI PNG'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, 2018.

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 PNG Book 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
I-A-17	Net Salvage

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

A. Yes. I provided testimony on depreciation matters for the Company in a prior UGI Penn Natural Gas ("PNG") base rate case at Docket No. R-2008-2079660, the prior two UGI Central Penn Gas ("CPG") base rate cases at Docket No. R-2010-2214415 and Docket No. R-2008-2079675 and the most recent base rate case for UGI Gas filed last year at Docket No. R-2015-2518438. Prior to those rate filings, I prepared exhibits for the depreciation study in UGI Gas's previous base rate case filed in 1995 at Docket No. R-00953297.

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

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

A. Yes, I am attaching and sponsoring the following exhibits: UGI PNG Exhibit C (Fully Projected), UGI PNG Exhibit C (Future) and UGI PNG Exhibit C (Historic). UGI PNG Exhibit C (Fully Projected) presents the summarized depreciation calculations and supporting tables related to the fully projected future test year ending September 30, 2018 (“FPFTY”). UGI PNG Exhibit C (Future) presents summarized depreciation calculations and supporting charts and tables related to the depreciation study for the future test year ending September 30, 2017 (“FTY”). UGI PNG Exhibit C (Historic) presents the summarized depreciation calculations and supporting tables related to the historic test year ended September 30, 2016 (“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 PNG Exhibit C (Future) contains additional information including the supporting charts and life tables related to the service life estimates.

Q. Does UGI PNG Exhibit C (Fully Projected) accurately portray the results of your depreciation study as of September 30, 2018?

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 PNG Exhibit C (Future) and UGI PNG Exhibit C (Fully Projected).

A. The depreciation study report in UGI PNG Exhibit C (Future) consists of eight parts including charts and tables filed in the Company's most recent service life study report submitted to the PA PUC in March 2016 based on gas plant in service as of September 30, 2015. 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, 2017. 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, 2017. 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 2013 through 2017.

UGI PNG 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, 2018. The descriptions and explanations presented in UGI PNG Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI PNG Exhibit C (Fully Projected). The graphs and tables related to service life presented in UGI PNG Exhibit C (Future) also support the service life estimates used in UGI PNG Exhibit C (Fully Projected) and UGI PNG Exhibit C (Historic), inasmuch as the estimates are the same for all three test years.

The results of the study are set forth in Part II in UGI PNG Exhibit C (Fully Projected). Table 1, pages II-3 through II-4 of UGI PNG Exhibit C (Fully Projected), presents the estimated survivor curve, the original cost and depreciation reserve at September 30, 2018, and the calculated annual depreciation rate and amount for each account or subaccount of Gas Plant in Service. Table 2, pages II-5 through II-6 of UGI PNG Exhibit C (Fully Projected), presents the bringforward to September 30, 2018, of the depreciation reserve as of September 30, 2017. Table 3, pages II-7 through II-8 of UGI PNG Exhibit C (Fully Projected), presents the calculation of the book depreciation amounts for the FPFTY. Table 4, page II-9 of UGI PNG Exhibit C (Fully Projected), presents the experienced and estimated net salvage for fiscal years 2014 through 2018. The amortization of net salvage is based on experienced and estimated net salvage during the period October 1, 2013 through September 30, 2018. The summary tables and detailed depreciation calculations set forth in UGI PNG Exhibit C (Fully Projected) as of September 30, 2018, are organized and presented in the same manner as those presented in UGI PNG Exhibit C (Future) as of September 30, 2017.

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

A. UGI PNG Exhibit C (Historic) is organized similar to UGI PNG Exhibit C (Fully Projected). UGI PNG 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, 2016. The descriptions and explanations presented in UGI PNG Exhibit C (Future) are also applicable to the depreciation calculations presented in UGI PNG Exhibit C (Historic). The same depreciation methods and procedures used to calculate depreciation were used in all three test year periods. The summary tables and detailed depreciation calculations as of September 30, 2016, are organized and presented in the same manner as those as of September 30, 2018 with two exceptions. Tables 2 and 3 presented in UGI PNG Exhibit C (Fully Projected) are not necessary and, therefore, are not presented in UGI PNG Exhibit C (Historic).

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

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

A. My use of the term "depreciation" is in accord with the definition set forth in the Uniform System of Accounts prescribed for 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.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation and Service Life Study Report filed in March 2016?

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

For General Plant Accounts 391, 393, 394, 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, 2018, the original cost of gas plant in service is $957,753,244 as shown in column 3 of Table 1 on pages II-3 through II-4 of UGI PNG Exhibit C (Fully Projected). This amount includes $922,462,683 of Gas Plant and $35,290,561 of Other Utility Plant allocated to UGI PNG. Other Utility Plant is primarily comprised of plant assets included in Common Plant and Information Services ("IS"). The assets included in Common Plant and IS are assets that are shared and jointly used among the divisions at UGI Corporation including UGI PNG. The costs related to Common Plant and IS are allocated to UGI PNG at 14.89 percent and 28.17 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 was assigned to UGI PNG. Also, the administrative office building located at Empire Yard Service Center ("Empire") in Wilkes Barre, PA is 100 percent included in Account 390.1, Structures and Improvements in UGI PNG. However, in recent years, a portion of the administrative building at Empire has been occupied by UGI Electric Division personnel. Therefore, a portion of the original cost and depreciation expense at Empire related to the Electric Division was deducted from UGI PNG's measure of value and depreciation expense claim.

VI. THE ACCRUED DEPRECIATION CLAIM

Q. Have you determined UGI PNG's accrued depreciation for ratemaking purposes as of September 30, 2018?

A. Yes. I have determined the allocated book depreciation reserve as of September 30, 2018, to be $295,124,431.

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 PNG's allocated book depreciation reserve as of September 30, 2017?

A. The book depreciation reserve allocated to UGI PNG as of September 30, 2017, is set forth in column 4 of Table 1 of UGI PNG Exhibit C (Future). Table 2 of UGI PNG Exhibit C (Future) presents an annual bringforward of the book depreciation reserve as of September 30, 2016, using estimated accruals, retirements, salvage and cost of removal for the twelve months October 2016 through September 2017. The table sets forth, by plant account, the beginning book reserve balance as of September 30, 2016, the estimated reserve activity, and the ending reserve balance as of September 30, 2017. 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 PNG 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, 2016, by plant account, shown in column 2 of Table 2 was obtained from UGI PNG's books and records.

Q. Please explain the manner in which you projected the depreciation accruals for the twelve months ended September 30, 2017.

A. The depreciation accruals for the twelve months ended September 30, 2017, by plant account, were estimated by applying the annual depreciation accrual rates calculated as of September 30, 2016, to the projected average 2016 plant balance. The average balance for the twelve months ended September 30, 2017, 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, 2012 through September 30, 2017.

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 2012 through 2016, 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, expressed as a percent of retirement amounts for the five years 2012 through 2016, to the projected retirement amounts.

Q. Was the book reserve at September 30, 2018, 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 2017 were based on applying the depreciation rate to average monthly plant balances for purposes of calculating the book reserve as of September 30, 2018.

VII. <u>THE ANNUAL DEPRECIATION EXPENSE CLAIM</u>

Q. Have you determined UGI PNG'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 $23,793,932 and consists of $21,079,110 of annual accruals to recover original cost and $2,714,822 of net salvage amortization. These amounts are set forth in column 6 of Table 1 in UGI PNG Exhibit C (Fully Projected).

Q. How did you determine the annual accruals of $21,079,110?

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

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

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

A. The service life study consisted of: compiling historical data from records related to UGI PNG's gas plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning UGI PNG'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 PNG's gas plant?

A. The data consisted of the entries made by UGI PNG to record gas plant transactions during the period 1954 through 2015. 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 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 PNG 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 36-R2.5 curve indicates an average service life of thirty-six years; a Right-skewed, or R2.5, type curve (the mode occurs after average life for right modal curves); and a relatively medium height, 2.5, for the mode (possible modes for R type curves range from 0.5 to 5).

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

A. Yes. Field trips are conducted periodically in order to be familiar with the operation of the company and observe representative portions of the plant. Field trips are conducted each time a service life study is performed. Service life study reports are submitted to the PA PUC every five years, at minimum. UGI PNG's most recent service life study report was submitted in March 2016. Facilities visited during field trips, generally include representative city gate stations, district regulating stations, service centers, etc. The most recent field trip was conducted in January 2016. 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 1992 and remaining lives consistent with the equal life group procedure for plant installed in 1992 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 PNG Exhibit C (Historic), UGI PNG Exhibit C (Future) and UGI PNG Exhibit C (Fully Projected). The detailed tabulations of the depreciation calculations are presented in Part III of UGI PNG Exhibit C (Historic) and UGI PNG Exhibit C (Fully Projected) and Part VII of UGI PNG Exhibit C (Future).

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

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

Q. Please describe briefly the average service life procedure that you used in conjunction with the straight line remaining life method for plant installed prior to 1992.

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 1992 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, 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. <u>ILLUSTRATION OF DEPRECIATION STUDY PROCEDURE</u>

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

A. I will use Account 376.2, Mains – Other than Plastic, to illustrate the manner in which the study was conducted. Account 376.2 represents 28 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 1954 through 2015. These data have been coded in the course of UGI PNG'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 and cast iron mains are still in service. The life analysis was performed and the Iowa 72-R2.5 survivor curve was judged most appropriate for this account and is the survivor curve used for this filing. The survivor curve estimate used in the previous service life study was the Iowa 70-R2 survivor curve. The Iowa 72-R2.5 survivor curve is an excellent fit for the original curve based on the company's retirement experience for the period 1954-2015. The proposed 72-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-9 of UGI PNG Exhibit C (Future). The original life table for the 1954-2015 experience band is set forth on pages VI-10 through VI-13.

The calculation of annual depreciation, the second phase, for the original cost of steel mains in service at September 30, 2017, is presented by vintage in Part VII on pages VII-19 through VII-21 of UGI PNG Exhibit C (Future) for Gas Plant in Service. The detailed depreciation calculations at September 30, 2018 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 1991 and prior vintages.

The accrued depreciation for vintages subsequent to 1991 was calculated by the equal life group procedure using the Iowa 72-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 72-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 72-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-21 of UGI PNG Exhibit C (Future) was brought forward to column 7 of Table 1 on page V-4 of the exhibit and divided by the total original cost in column 3 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 376.2 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 PNG 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, 2017, is presented by vintage in Part VII on page VII-55 of UGI PNG 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-55 of UGI PNG Exhibit C (Future) was brought forward to column 7 of Table 1 on page V-4 of UGI PNG Exhibit

C (Future). A similar process was performed for UGI PNG Exhibit C (Fully Projected) and UGI PNG 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, 2018, is presented by vintage on page III-56 of UGI PNG Exhibit C (Fully Projected) and summarized in Table 1 on page II-3.

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

A. The life span procedure was applied to major structures in Account 390. The life span procedure was used for groups such as buildings in which concurrent retirement of all property in the group is expected. The life span of both the original installation and subsequent additions is the number of years between installation and final retirement of the group. The complete details, by vintage, of the accrued depreciation and remaining life accrual calculations are set forth for each structure in Part III of UGI PNG Exhibit C (Historic) and UGI PNG Exhibit C (Fully Projected) and in Part VII of UGI PNG 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 PPL Gas Utilities Corporation’s (“PPL Gas”) most recent rate filing (Docket No. R-00061398). This procedure is consistent with how other Pennsylvania public utilities account for net salvage and is the method used in preparing the company’s Annual Depreciation Reports submitted each year to the Commission.

Q. Earlier in your testimony you indicated that UGI PNG’s annual depreciation expense consists, in part, of $2,714,822 of net salvage amortization. How did you determine that amount?

A. The $2,714,822 is the result of determining the five-year average of net salvage experienced and estimated during the period of October 1, 2013 through September 30, 2018. Net salvage is defined in the Uniform System of Accounts as gross salvage less cost of removal. For most gas utilities, including UGI PNG, 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 PNG Exhibit C (Future) and Part IV of UGI PNG 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 and future test years. 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 PNG Exhibit C (Historic) and UGI PNG Exhibit C (Future) in the section titled "Cumulative Depreciated Original Cost".

Q. Does this conclude your direct testimony?

A. Yes, it does.