UGI GAS STATEMENT NO. 6 – DAVID E. LAHOFF

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Docket No. R-2015-2518438

UGI Utilities, Inc. – Gas Division

Statement No. 6

Direct Testimony of
David E. Lahoff

Topics Addressed:	**Test Years Sales/Revenues** **Rate Structure** **EE&C Rider** **USP Rider** **Revenue Allocation and Rate Design** **GET Gas Reporting** **Tariff Changes**

Dated: January 19, 2016

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David E. Lahoff. My current business address is 2525 N. 12th Street, Suite 360, Reading, Pennsylvania 19612.

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

A. I am employed by UGI Utilities, Inc. ("UGI") as Manager, Tariff & Supplier Administration.

Q. Please provide your educational background.

A. I received an undergraduate degree in business from The Pennsylvania State University and a Masters Degree in Business Administration from The University of Connecticut.

Q. Please provide your professional experience.

A. In 2002, I was named Manager, Special Projects for UGI. In 2003, I became Manager, Customer Accounting Services for UGI, where my responsibilities included the administration of all customer accounting functions. Beginning in 2007, I returned to the position of Manager, Special Projects to oversee a customer information system conversion project. Following the completion of that project, in 2009, I was named Manager of Rates. In 2014, I assumed the position of Manager, Tariff & Supplier Administration.

Q. What are your current areas of responsibility?

A. My current responsibilities include (1) all aspects of tariff and rate administration, including interactions with natural gas suppliers under our natural gas supplier tariffs, (2) revenue planning and (3) oversight of UGI's gas management system.

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

A. Yes, I have testified in the following dockets: UGI Central Penn Gas, Inc. ("CPG") 2009 Base Rate Case, Docket No. R-2008-2079675; UGI Penn Natural Gas, Inc. ("PNG") 2009 Base Rate Case, Docket No. R-2008-2079660; UGI Utilities, Inc. – Gas Division ("UGI Gas" or the "Company") 2009 Annual Gas Cost Filing, Docket No. R- 2009-2105911; UGI Gas Petition to Implement a Purchase of Receivables Program and Merchant Function Charge, Docket No. P-2009-2145498; CPG 2011 Base Rate Case, Docket No. R-2010-2214415; UGI Gas Procurement Charge Filing, Docket No. R-2012-2314235; PNG Gas Procurement Charge Filing, Docket No. R-2012-2314224; CPG Gas Procurement Charge Filing, Docket No. R-2012-2314247; UGI Gas, PNG and CPG Growth Extension Tariff ("GET Gas") Filing, Docket No. P-2013-2356232; and UGI Utilities, Inc. - Electric Division Default Service Filing, Docket No. P-2013-2357013.

Q. Please describe the purpose of your testimony.

A. I will address: (1) development of the historic test year ended September 30, 2015 ("HTY"), future test year ending September 30, 2016 ("FTY"), and fully projected future test year ending September 30, 2017 ("FPFTY"), sales and revenues, including use per customer adjustments due to energy savings from the proposed Energy Efficiency and

Conservation ("EE&C") Plan; (2) rate structure, including elimination of certain rate schedules, and the new EE&C Rider and Universal Service Program ("USP") Rider; (3) revenue allocation and rate design; (4) update to the GET Gas Pilot Program; and (5) other proposed tariff modifications.

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

A. Yes, I am sponsoring the following Exhibits: UGI Gas Exhibit DEL-1 (15 year normal heating degree days); UGI Gas Exhibit DEL-2 (Multi-year Normal Trend of use per customer – residential and non-residential); UGI Gas Exhibit DEL-3 (FPFTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-4 (FTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-5 (HTY Sales and Revenue Adjustments); UGI Gas Exhibit DEL-6 (Detail of Usage per Customer by Class as shown on UGI Gas Exhibit DEL-3); UGI Gas Exhibit DEL-7 (Calculation of EE&C Rider); UGI Gas DEL-8 (Calculation of the USP Rider and the Adjustment to Annual USP Reconciliation); UGI Gas Exhibit DEL-9 (Rate NNS calculation); UGI Gas Exhibit DEL-10 (Rate MBS calculation); UGI Gas Exhibit DEL-11 (Recalculation of GPC); UGI Gas Exhibit DEL-12 (Recalculation of MFC percentages); UGI Gas Exhibit DEL-13 (Recalculation of GET Surcharge); UGI Gas Exhibit DEL-14 (Calculation of GET Gas Revenues); and Schedules D-5A and D-5B of UGI Gas Exhibit A. 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. SALES AND REVENUES

A. Development of FPFTY Sales and Revenues

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

A. FPFTY sales and revenues were developed by annualizing and normalizing the Company's 2017 fiscal year planned sales and revenue budget, adjusted to reflect the most recently available growth forecast. Annualized sales were determined by developing sales and revenue adjustments reflective of projected customer counts and annual expected use per customer as of September 30, 2017 for a full twelve- month period by reviewing historic usage data and applying regression analysis techniques. Both the Company's 2017 fiscal year planned sales and revenue budget and the Company's FPFTY reflect normal heating degree days of 5,214 based upon an average over a fifteen year period ending December 31, 2014. UGI Gas Exhibit DEL-1 provides the supporting calculation of the normal degree days utilized.

Q. Is the use of average temperature data for a fifteen-year period consistent with the methodology used by PNG and CPG for calculating normal heating degree days in previous base rate cases?

A. Yes. PNG used a fifteen-year period to develop normal heating degree days in its 2009 base rate case, and CPG used this methodology in its 2009 and 2011 base rate cases.

Q. Please explain the process for developing the Company's fiscal year 2017 planned sales and revenue budget.

A. The planned sales and revenue budget is a joint effort of the Marketing and Rates Departments, with Marketing providing 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 budget process is described in the direct testimony of Company witness Ann P. Kelly (UGI Gas Statement No. 2).

In developing sales and revenues, the Vice President, Marketing and Customer Relations, with input and assistance from other marketing employees, budgets the number of customers by class. Various factors are considered in developing customer budgets, including: the trend in losses and conversions to and from other energy sources; the level of applications and inquiries for service, new construction activity; current and projected economic factors; and the costs of competing fuels. The usage per customer reflected in the planned 2017 budget was developed by carrying forward the same levels of usage per customer derived for the fiscal year 2016 budget, which were developed using normalized twelve-month trends for the period ending March 2015 incorporating historic actual weather and actual usage per customer class, to develop projected customer usage under normal weather conditions. Planned budgeted numbers of customers and usage per customer for these customer classes are then combined to produce planned budgeted sales. Sales are allocated by month, and appropriate rates or rate blocking are applied to derive planned budgeted revenues. Sales and revenues related to large contract customer classes are developed by the Marketing Department on a customer specific basis using customer input where appropriate.

The derivation of the 2017 planned budget reflects a preliminary forecast which will be subsequently updated during 2016 as part of the normal budget process, which is conducted several months prior to the start of the new fiscal year. The methodology applied to develop normalized FPFTY use per customer, FTY use per customer, and HTY use per customer is the same for all three periods. In particular, the methodology used is appropriate for ratemaking purposes given the longer term period over which new rates are likely to be in effect as compared to the Company's typical budget, which is shorter term in nature.

Q. Please describe the adjustments made to FPFTY year sales and revenues for the twelve months ending September 30, 2017.

A. A summary of all adjustments made to the 2017 planned budget in order to develop FPFTY sales is shown on UGI Gas Exhibit DEL-3(a). In total, these adjustments reflect a reduction to sales of 5,606 MMcf and a reduction to revenue of $68.5 million.

Q. Please explain the "Adjustment for Customer Changes" shown on UGI Gas Exhibit DEL-3(b).

A. The "Adjustment for Customer Changes" annualizes customer counts to anticipated end of test year levels based on the Company's most recent forecast for the FPFTY. In particular, this adjustment includes a net increase of 977 residential heating customers and a net increase of 161 non-residential heating customers.

Q. How is this adjustment quantified?

A. UGI Gas Exhibit DEL-3(b) provides the calculation of the associated sales and revenue adjustments for the stated customer count increases. In total, as reflected on UGI Gas Exhibit DEL-3(a), this adjustment increases sales by 0.093 MMcf and increases projected revenues by \$0.8 million, inclusive of revenues for recovery of purchased gas costs ("PGC") and exclusive of transportation customer adjustments discussed separately below.

Q. Please explain your next adjustment, "Adjustment for Annualized Use/Customer."

A. The "Adjustment for Annualized Use/Customer" annualizes usage per customer to projected end of year test levels based on a twenty-one year regression analysis of actual usage and degree day information for the period from January 1995 through September 2015, and forecasts end of FPFTY use per customer conditions using the regression results along with normal heating degree days. The results can be seen in UGI Gas Exhibit DEL-3(c), resulting in a net sales decrease of 4.34 MMcf and a net revenue decrease of \$33.1 million, inclusive of revenues for recovery of PGC and exclusive of transportation customer adjustments discussed separately below.

Q. Why did UGI Gas utilize a regression period of twenty one years?

A. Utilizing this approach provides a large enough sample set of data to smooth out short-term variations and capture the underlying long-term use per customer trend in order to more accurately project usage per customer during the period rates are likely to be in effect. Please see UGI Gas Exhibits DEL-2(a) and DEL-2(b), which contain graphs that illustrate the long-term usage trend for the Company's core residential and commercial heating customers, and clearly show that, although there are short-term fluctuations which occur in certain periods, the values consistently revert to the long-term trend observed over this twenty-one period. In developing the data, the Company utilized an econometric regression model that incorporates four independent variables: use per customer, heating degree days, lagged heating degree days and time trend. While use per customer and heating degree days capture annualized usage factors based on projected annualized customer changes and weather defined by a normal standard, the time trend variable of this regression captures trends underlying changes in usage per customer over time. These trends can be varied, but as a comprehensive variable, "trend" will capture the impacts of conservation items and measures, including, but not limited to: (1) regular appliance replacements; (2) accelerated appliance replacements; (3) high-efficiency appliance installations; (4) setback thermostat installations; (5) modifications to new and existing buildings that are designed to decrease energy consumption; and (6) changes in consumer usage behavior due to other economic influences. Given the number of variables that can influence customer usage over time, and the difficulty in identifying, quantifying and tracking all variables over time, the use of a trend variable can be used to provide a comprehensive indicator of usages trends, which can then be used to forecast for a future period.

Q. Is the econometric model you described the same as the model utilized in the 2009 PNG, and 2009 and 2011 CPG base rate cases?

A. The econometric model uses the same set of variables, but uses twenty one years of data, as opposed to five years of data. In their base rate cases, CPG and PNG did not have access to as much historical data as the Company has in this proceeding. Therefore, CPG and PNG had to use a more abbreviated historical period. The twenty-one years of history are useful in identifying clear trends which should be evaluated for rate making purposes.

Q. Do the adjustments to use per customer for the FPFTY include the impact of Company's proposed EE&C Plan?

A. Yes. As part of its base rate filing, the Company is proposing to implement an EE&C Plan. The energy savings associated with the program will primarily occur in residential and small commercial customer usages. UGI Gas Exhibit DEL-3(m) shows the summary energy savings by Rates R, RT, N and NT, based on the five-year average annual savings for the program. The exhibit also contains the energy savings impact on a use per customer basis. The incremental impact on use per customer for Rates R and RT is 0.5 Mcf, and the incremental impact on use per customer for Rates N and NT is 1.5 Mcf. These incremental reductions in use per customer are included in the calculation of adjusted use per customer for the FPFTY. The buildup for the overall energy savings is addressed in the direct testimony of Company witness Theodore M. Love (UGI Gas Statement No. 11). This adjustment decreases total sales by 0.22 MMcf and reduces revenue by $1.5 million.

Q. Please explain the adjustment titled "Adjustment for Transport Changes" as shown on UGI Gas Exhibit DEL-3(a), 3(b), 3(b)1, 3(c), and 3(c)1.

A. The "Adjustment for Transport Changes" is the summation of several adjustments made for the Company's transportation customers for the FPFTY. This adjustment reduces projected sales by 1.1 MMcf and decreases revenues by $2.35 million, as shown in summary on UGI Gas Exhibit DEL-3(a) and detailed on UGI Gas Exhibits DEL-3(b), 3(b)1, 3(c) and 3(c)1 The adjustment for large transportation customers was developed by UGI Gas marketing personnel following their review of individual large customer accounts and market segments. It reflects anticipated increases or reductions from original fiscal year 2017 planned budget levels in the sales and revenues for these accounts. Changes in customer counts for small transportation customer classes have been developed from UGI Gas marketing forecasts for counts at the end of the FPFTY, and associated usage per customer for the small transportation customer groups were included within the 21-year regression analysis. See UGI Gas Exhibit DEL-6 for details on use per customer by class.

Q. Please explain the "Adjustment for PGC" shown on UGI Gas Exhibit DEL-3(a).

A. The "Adjustment for PGC" shown in summary on UGI Gas Exhibit DEL-3(a) represents an annualization of the FPFTY PGC revenues using the PGC rate in effect as of December 1, 2015 for the FPFTY period. UGI Gas Exhibit DEL-3(d) provides the calculations for this adjustment. This adjustment decreases PGC revenues for the FPFTY by $11.32 million.

Q. Please explain the three adjustments "Adjustment for MFC," "Adjustment for LISHP," and "Adjustment for GPC" shown in summary on UGI Gas Exhibit DEL-3(a).

A. The "Adjustment for MFC" annualizes Company's Merchant Function Charge ("MFC") revenues for the FPFTY based on the MFC surcharge rate in effect as of December 1, 2015. The "Adjustment for LISHP" annualizes Company's USP surcharge revenues for the FPFTY based on the Low Income Self Help Program ("LISHP") Rider rate in effect as of December 1, 2015. The "Adjustment for GPC" annualizes the Gas Procurement Cost ("GPC") revenues to reflect the volume variance to the original fiscal year 2017 planned budget. The MFC Adjustment decreases projected revenues by $184,000; the LISHP adjustment increases revenues by $2.0 million; and the GPC adjustment decreases revenues by $171,000. Additional details for these three adjustments are provided on UGI Gas Exhibits DEL-3(e), 3(f) and 3(g).

Q Please explain the "Adjustment for Interruptible."

A. The "Adjustment for Interruptible" annualizes the Company's interruptible revenues for the FPFTY at the level of revenue based on a proxy cost of service of $4.9 million. The methodology for this proxy cost of service is discussed by UGI Gas witnesses Paul J. Szykman (UGI Gas Statement No. 1) and Paul R. Herbert (UGI Gas Statement No. 4). In total, the Interruptible Adjustment decreases revenues by $15.7 million.

Q. Please explain the three adjustments shown on UGI Gas Exhibit DEL-3(a): "Adjustment for Transportation Service Revenues," "Adjustment for Excess Take" and "Adjustment for Rate N Minimum."

A. The "Adjustment for Transportation Service Revenues," detailed in UGI Gas Exhibit DEL-3(i), reflects the proposed elimination of the following capacity release and transportation service related fees: Pooling Fees, System Access Fees and Information Service Fees. It also assumes a zero level for Supply Transfer Fees given the very low level of transfer activity in prior years and the proposal to move a transaction base fee, rather than a volumetric based fee. The adjustments for transportation service revenues reduce revenue by $6.7 million. The "Adjustment for Excess Take," detailed in UGI Gas Exhibit DEL-3(j), reflects the assumption that customers will evaluate new service elections as part of the implementation of new tariff rates, and will make the necessary adjustments to avoid

Excess Take penalties in the FPFTY year. The Excess Take adjustment reduces revenue by $600,000.

The "Adjustment for Rate N Minimums," detailed in UGI Gas Exhibit DEL-3(l), reflects the proposed elimination of Rate N minimum bill requirements. The Rate N minimum adjustment reduces revenue by $1.3 million.

Q Please explain the adjustment on UGI Gas Exhibit DEL-3(k) "Adjustment for STAS."

A. The "Adjustment for STAS" zeros out the current UGI Gas State Tax Adjustment Surcharge ("STAS") from its current level of (0.55%). The STAS adjustment increases projected revenues by $1.8 million.

Q Please explain the adjustment on UGI Gas Exhibit DEL-3(n) "Adjustment for GET Gas."

A. The "Adjustment for GET Gas" reflects a reduction in GET Gas revenues primarily due to the higher than forecasted number of customers that are choosing to pay the GET Gas charge upfront as a lump sum instead of monthly, which eliminates the revenue from the return on investment portion of the monthly GET Gas charge. The revised revenues were developed by annualizing the projected payments in September 2017. This adjustment reduced revenues by $238,000.

Q. Do the adjusted FPFTY revenues exclude revenues related to off-system sales?

A. Yes.

Q. Do the FPFTY revenues exclude revenues associated with the proposed discontinued tariff fees?

A. Yes. As discussed in the section on Tariff Changes, the Company is proposing to eliminate a number of tariff fees to improve customer satisfaction and simplify its tariff administration, and has adjusted "Other Gas Revenues" by the amount of the fees associated with the elimination of the tariff charges. This adjustment of Other Gas Revenues reduces Other Gas Revenues by $3.3 million, as shown on UGI Gas Exhibit A (Fully Projected), Schedule D-5B.

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

Q. How were annualized and normalized sales and revenue determined for the FTY ending September 30, 2016?

A. Budgeted sales and revenues serve as the starting point for the development of the annualized and normalized FTY sales and revenues shown in UGI Gas Exhibit DEL-4(a). All of the adjustments that were made in the development of the FPFTY, with the exception of the adjustment related to the proposed EE&C program, were also made in the development of the FTY.

Q. How were annualized and normalized sales and revenue determined for the HTY ended September 30, 2015?

A. Historic sales and revenues serve as the starting point for the development of the annualized and normalized HTY sales and revenues shown in UGI Gas Exhibit DEL-5(a). The adjustments that were made in the development of the HTY were substantially the same as the adjustments made in the development of the FTY.

III. RATE STRUCTURE

Q. Please describe the changes in rate structure proposed by the Company in this proceeding.

A. The Company has not had a base rate proceeding in over twenty years. In general, the Company seeks to update and more closely align its tariff and rate schedules with those of PNG and CPG, who have had more recent base rate proceedings, and to simplify its rate design by eliminating a number of existing rate schedules that are no longer necessary or appropriate.

Q. Please identify the rate schedules and rates the Company is proposing to eliminate and its basis for doing so.

A. The Company is proposing to eliminate the following rate schedules and PGC rates:

- Rate BD (Business Development Rate) – This is a retail (*i.e.*, a non-transportation) rate schedule designed for higher volume customers willing to execute a service agreement with the Company for a Daily Contract Requirement of not less than 50 Mcf. Rate BD customers also qualify for a PGC ("PGC 2") rate that has separate demand and commodity components, which was initiated by the Company in 1993 to make PGC retail service more attractive to higher volume customers. As the retail natural gas market has matured, however, all of the Company's Rate BD customers have migrated to transportation rate schedules, so the Company is proposing to eliminate this rate. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.

- Rate PV (Propane Vaporization Service) – Under this rate, the Company would vaporize propane as an agent for any Commercial or Industrial customer of the Company served under other rate schedules, where the customer provided suitable commercial grade propane fuel to the Company for vaporization. The Company is proposing to eliminate this rate because there are no customers currently using it and there is no prospect of any future use. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.
- Rate SS (Storage Service) – Under this rate schedule, the Company would provide storage capacity on an agency basis when suitable gas or other fuel is supplied by the customer. This rate schedule was developed and implemented before the Federal Energy Regulatory Commission ("FERC") established the capacity release mechanism as the sole means, with certain limited exceptions, for making FERC-jurisdictional pipeline and storage capacity available to third parties. The Company is proposing to eliminate this rate because there currently are no customers served under this rate, and it is not clear whether this service could be provided in any event under current FERC rules. Also, there is no comparable rate schedule in the tariffs of PNG and CPG.
- Rates IL (Interruptible Service – Large Volume) and IS (Interruptible Service – Small Volume) – The Company is proposing to merge these two rate schedules into a new Rate IS (Interruptible Service). Since interruptible service is priced against the cost of alternative fuel options, there is little difference between these two rate

schedules other than minimum bill requirements, which will be combined into a new unified minimum bill requirement under the Company's proposed new Rate IS, along with applicable retainage requirements. The proposed Rate IS is also consistent with the Rate IS rate schedules in the tariffs of PNG and CPG.

- Rate CIAC (General Service – Commercial and Industrial Air Conditioning) – This is a retail rate available to commercial or industrial customers using gas for air conditioning purposes. PGC 2 rates apply to Rate CIAC usage. The Company is proposing to eliminate this rate, which was adopted at a time when it was thought that gas air-conditioning would develop into a significant market and when there were more significant differences in costs between PG 1 and PGC 2. As there currently are only 17 customers on this rate, these customers will be migrated to full year service under Rates N (General Service – Non-Residential) or NT (General Service – Non-Residential – Transportation). While PNG and CPG have a comparable rate schedule in their tariffs, the Company anticipates that they will seek to eliminate these rate schedules in the future.
- Rate CT (General Service – Commercial and Industrial Air Conditioning – Transportation) – This is the comparable transportation rate for commercial or industrial customers using gas for air conditioning purposes. The Company is also proposing to eliminate this rate schedule because there are only four customers served under the rate schedule, all of whom will now be served under Rate NT (General Service – Non-Residential - Transportation). While PNG and CPG have a comparable rate schedule in their tariffs, the Company anticipates that they will seek to eliminate these rate schedules in the future.

- PGC 2 – Given the proposed elimination of Rate Schedules BD and CIAC, the only Rate Schedules to which its PGC 2 rate is applicable, the Company is also proposing to eliminate its PGC 2 rate and serve all retail customers subject to its PGC rates under a single PGC rate.
- Rate EC (Environmental Conversion Rider) – This rider permits a discount to customers converting from an alternate fuel where the customer (1) permanently retires storage tanks or other equipment for the utilization of alternative energy supplies and (2) incurs a "demonstrated economic penalty" because of its conversion to gas. The Company proposes to eliminate this rider because the Company anticipates that it will not have any customers utilizing this rider at the time the proposed tariff changes become effective and future considerations for customers may now be made under the proposed Technology and Economic Development ("TED") Rider.
- Rate CDS (Cogeneration Delivery Service) – This Rate is available to customers who wish to use gas to; (a) generate electricity and/or (b) produce a combination of mechanical and heat energy where mechanical energy production represents no less than 25% of total energy output. A customer must have an indicated gas usage of at least 3,000 Mcf per year. The Company is proposing to eliminate this rate due to the minimal number of customers on this rate. There are only 2 customers currently on this rate. In addition, there is no comparable rate at PNG or CPG. The Company proposes to move these customers to Rate LFD, which would be the most appropriate rate schedule given their size and load profile, and to the extent

required, utilize the proposed TED Rider to preserve the economic substance of the existing service agreements currently available under Rate CDS.

Q. How does the Company propose to effectuate the changes resulting from these rate eliminations?

A. If the Company's proposed rate schedule and PGC 2 rate deletions are approved by the Commission, the Company will: (1) tender new Rate IS service agreements to existing Rate IS and IL customers that, to the extent possible under the Commission's ruling, will preserve the economic substance of the existing service agreements for their remaining term; (2) contact each existing Rate CIAC and CT customer to help them select an alternative rate schedule, and if no decision is made, move the customer to Rate N (the Company cannot automatically move a customer to Rate NT since the customer must select an alternate supplier in order to receive service under Rate NT); (3) contact the two Rate CDS customers and provide them with their comparative rate information in order to help them select an alternative rate schedule; (4) move all existing PGC 2 customers to the new unified PGC rate; and (5) roll any remaining PGC 2 rate over/under collection, which is anticipated to be very small, into the new unified PGC rate E-factor.

Q. Is the Company proposing any additional rates or riders?

A Yes, the Company is proposing a new rider to recover the costs associated with the implementation of its proposed EE&C Plan. In addition, the Company is proposing to replace its current LISHP Rider with a USP Rider. Finally, the Company is proposing a new TED Rider , which is discussed in the direct testimony of Robert R. Stoyko (UGI Gas Statement No. 7).

Q. Please describe the calculation of the proposed EE&C Rider.

A. The Company is proposing to establish an EE&C Rider, which will appear as a separate line item on customer bills, to recover program costs related to the Company's proposed EE&C Plan for fiscal years 2017-2021, as described in the testimony of Company witness Theodore M. Love (UGI Gas Statement No. 11). The EE&C Rider will be computed separately for each of the following two customer classes: (i) Residential customers served under Rate Schedules R and RT (ii) Non-Residential customers served under Rate Schedules N, NT, DS, and LFD. The initial proposed EE&C Rider rates, as developed in UGI Gas Exhibit DEL-7 are:

- Residential Rates R and RT: $0.0778/Mcf.
- Non-Residential Rates N, NT, DS, LFD: $0.0278/Mcf.

The EE&C Rider will apply to all customers served under the rate schedules identified above and the EE&C Rider revenues shall be subject to the STAS.

Q. Please describe the calculation of the proposed USP Rider.

A. The Company is not proposing any policy or procedural changes to its current, recently-approved Universal Service and Energy Conservation Plan. The Company is, however, proposing to modify its recovery mechanism of USP costs to mirror the Commission-approved reconcilable riders currently in place at CPG and PNG. As a result, the Company's LISHP Rider will be replaced by the proposed USP Rider. The initial proposed

USP Rider surcharge is $0.2927 per Mcf, as calculated in UGI Gas Exhibit DEL-8. In conjunction with the proposed USP Rider, the Company is also proposing to modify the tariff section for the annual reconciliation of the proposed USP Rider to include an adjustment for amounts granted to the number of participants receiving Customer Assistance Program ("CAP") credits and preprogram arrearage in excess of 10,000. The adjustment related to CAP credits and preprogram arrearage will be equal to 8.48%. The adjustment is based on the 3-year average of the difference between the gross write-off percentage for low-income customers identified by UGI Gas's system and the gross write off percentage for all other residential customers, adjusted for write-off recoveries. See UGI Gas Exhibit DEL-8 for the calculation of this adjustment. See UGI Gas Exhibit F – Proposed Tariff for the proposed modifications to the USP Rider section of the tariff. Further, see the direct testimony of Company witness Robert R. Stoyko (UGI Gas Statement No. 7) for the participation levels.

IV. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

Q. **Please summarize the Company's rate design and allocation of the revenue increase ratemaking philosophy.**

A. The Company's ratemaking goal is to implement reasonable rates that recover its cost of doing business. Rate schedules are generally designed to reflect movement toward class cost of service and to be competitive with prices of alternate energy sources, including bypass. Our rates and rate design seek to achieve efficient utilization of the Company's facilities and natural gas supplies.

Q. **What factors has the Company considered in establishing its rate structure?**

A. The Company considered both cost of service and value of service as the primary factors in determining revenue allocation and rate design. Other factors that were considered include competition, historic rate patterns, supply conditions, impacts upon customers, the local economy, the nature of our territory, the needs of our customers, utilization of facilities, and public acceptance of rate forms and changes.

Q. Did the Company consider customer migration between rate classes in allocating the proposed rate increase?

A. Yes. The Company has conducted an analysis of customers in Rate Schedules N and NT with annual volumes of 3,000 Mcf or more, and all Rate Schedule DS customers to determine which rate schedule would be the most economical under proposed rates, and has assigned these customers to their most economical rate schedule based on proposed rates for the purposes of projecting anticipated revenues.

Q. Please summarize how the proposed distribution revenue increase was allocated among the customer classes.

A Except for Rates XD and IS, whose rates are negotiated and established under their current service agreements, overall UGI Gas is proposing to move applicable rate classes above the system average rate of return at present rates approximately halfway toward cost of service, subject to the following conditions: (1) rate classes that are above the system average rate of return at present rates will receive an increase less than the system average distribution increase; and (2) the rate increase for rates classes that are below the system average rate of return at present rates will not exceed 150% of the system average increase.

In measuring cost of service, the Company relied on the cost of service studies prepare by Company witness Paul R. Herbert (UGI Gas Statement No. 4). In developing the allocations for interruptible service, Mr. Herbert presented two cost of service studies to establish a range of reasonableness. One study included an allocation of distribution main costs to the interruptible rate class, and a second study did not allocate any distribution main costs to the interruptible rate class. The Company then used an average of these two methods as the basis for allocating the proposed revenue increase. Table 1 below provides a summary of the proposed allocation of the increase and the relative class rates of return at present and proposed rates.

Table 1 COMPARISON OF RELATIVE RATES OF RETURN

Rate	% Increase (without gas costs)	Relative ROR- present rates	Relative ROR- proposed rates	Change in relative ROR	% change in relative ROR
R	39.90%	0.16	0.61	0.45	54%
N	22.70%	1.3	1.09	-0.21	-70%
DS	9.30%	3.28	2.14	-1.14	-50%
LFD	7.00%	6.4	3.7	-2.7	-50%
Total	26.60%	1.00	1.00	0	

Q. Please describe the revenue allocation and rate design for the residential Rate R customer group.

A. As evidenced by the cost of service study presented by Mr. Herbert, under present rates, the residential Rate R customer group (Rates R and RT) is producing a return of 0.71%, as compared to a system average return of 4.52%. This translates to a relative rate of return of 0.16 compared to the system average. In allocating revenues, the Company proposes to allocate $43.3 million of the revenue increase to the Rate R customer group in order to move it closer toward cost of service. This increase will result in an overall return of 5.01%

for the Rate R customer group, compared to the proposed system average of 8.17%, and a relative rate of return of 0.61.

As to rate design, the Company is proposing a Rate R customer group customer charge of $17.50 per month, as compared to the current charge of $8.55 per month, to better reflect the customer component of customer service. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $3.0123 per Mcf.

Q. Please describe the revenue allocation and rate design for the small commercial Rate N customer group.

A. For the small commercial Rate N customer group (Rates N and NT), current rates are producing a return of 5.89% with a relative rate of return 1.30. UGI Gas proposes to allocate $12.5 million of the revenue increase to the Rate N customer group in order to move the Rate N customer group closer toward cost of service. This increase will result in an overall return of 8.93% or a relative rate of return of 1.09.

As to rate design, the Company is proposing a Rate N customer group customer charge of $32.00 per month, as compared to the current charge of $8.55 per month, to better reflect the customer component of customer service. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $3.6932 per Mcf.

Q. Please describe the revenue allocation and rate design for the Rate DS.

A. For Rate DS, the applicable transportation rate for small to medium sized customers, current rates are producing a return of 14.86%, with a relative rate of return of 3.28. The Company proposes to allocate approximately $982,000 of the revenue increase to the Rate DS customers in order to move the Rate DS class closer toward cost of service. This increase will result in an overall class return of 17.48% or a relative rate of return of 2.14, by moving Rate DS by 50% toward a unity relative rate of return value.

As to rate design, the Company is proposing to maintain the current Rate DS monthly customer charge of $290.00 per month. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $2.9121 per Mcf.

Q. Please describe the revenue allocation and rate design for the Rate LFD.

A. For Rate LFD, the applicable transportation rate for medium to large sized customers, current rates are producing a return of 28.96%, with a relative rate of return of 6.40. The Company proposes to allocate approximately $1.75 million of the proposed revenue increase to the Rate LFD customers in order to move this customer class toward cost of service. This increase will result in an overall return of 30.22% or a relative rate of return of 3.70, by moving Rate LFD by 50% toward a unity relative rate of return.

As to rate design, the Company is proposing to maintain the current Rate LFD monthly customer charge of $700 per month. The Company also is proposing to replace the current declining block structure with a single block volumetric charge of $1.2133 per Mcf. The Company also is proposing a demand charge of $5.45/Mcfd to assist with system planning.

Q. Please describe the revenue allocation and rate design for the Rate XD.

A. For Rate XD, the rates for this class are based on current contracts as negotiated between the Customer and the Company given competitive considerations, the Company is not proposing any change to present rates.

Q. Please describe the revenue allocation and rate design for the Rate IS.

A. Rate IS, the applicable interruptible rate schedule for commercial and industrial customers, is an opportunistic rate schedule that is based on the relative price of natural gas versus alternative fuels or other customer alternatives. As such, the Company is at risk for those revenues if circumstances change, and there is no guarantee that current revenue levels will be achieved in the future, particularly considering the recent changes in the interruptible market over the past few years, such as declining price spreads and an increase in the number of interruptions in the winter season. These changes, if they continue, could lead to a substantial decline in interruptible revenue for the Company. For example, the NYMEX price for crude oil has declined from approximately $65 per barrel to under $40 as of December 2015. As a result, the NYMEX futures price spread between natural gas and number 2 heating oil has dropped from $18.08/MMBTU as recently as February 2014 to $7.43/MMBTU as of December 2015, a 59% decline. Since interruptible rates are based on prices for alternate fuels, the decline in price spreads could impact future contract negotiations and potentially lead to a decline in interruptible revenues. In addition to changes in price spreads, there has also been an escalation in the number of actual interruptions experienced by the interruptible rate class, due to weather and system constraints, that could change perceptions of the relative reliability of interruptible service and lead to customers taking additional actions. For example, customers could lock in heating oil inventories to ensure a continuation of operations during potential gas interruptions and then use that inventory of oil during the heating season instead of gas, even during periods when there is no interruption simply because the customer owns the oil.

As a result of the at-risk nature of the interruptible revenues and the market changes discussed above, the Company is reflecting, as a proxy, a level of interruptible revenue in its revenue allocation that is based on a cost of service allocation methodology, or $4.9 million. The Company assigned to the interruptible class an amount based approximately on the midpoint of the calculated results from two separate cost of service studies, one which allocated a portion of distribution mains to interruptible customers and one which did not allocate any mains costs to interruptible customers. The implied overall rate of return under these assumptions is 7.93% or a relative rate of return of 0.97. Please see the direct testimony of Paul J. Szykman (UGI Gas Statement No. 1) for additional detail on the Company's proposal on value of service pricing to the interruptible market and the treatment of revenues received under its Interruptible Service rates. Also see the direct testimony of Paul R. Herbert (UGI Gas Statement No. 4) for additional discussion of the cost of service allocation methodology.

Q. Please describe Rate NNS (No Notice Service) and any changes to this rate that the Company is proposing.

A. Rate NNS is a daily balancing service offered by the Company that is patterned after Rate NNS as offered at PNG and CPG. It provides an alternate election of a daily balancing tolerance for transportation customers, allowing a customer to optionally elect a balancing tolerance greater than the standard basic balancing provided by the Company. A customer is able to make a Rate NNS election up to its DFR (Daily Firm Requirement) contract demand level and pay only for the level chosen. The Company is proposing to update the tariffed NNS rate to reflect current conditions, while retaining the methodology used to develop the current rate.

Q. How were the proposed NNS rates developed?

A. The charge for providing service under Rate NNS is a monthly charge established using the Company's cost of interstate storage that can be utilized for balancing excess or shortfall requirements on the Company system, Columbia FSS storage. UGI Gas Exhibit DEL-9 shows the calculation of the Rate NNS charges, which were developed based on the same methodology used in the Company's last base rate case, as well as the methodology utilized by CPG and PNG in their respective last base rate cases, updated to reflect current costs and conditions. The proposed rate for unit rate for NNS is $0.0066 per Mcf compared to the current rate of $0.025 per Mcf, and the proposed NNS service per unit cost of demand is $0.1320/Mcf of demand ("Mcfd") compared to the current $0.050 per Mcf per day of elected Rate NNS.

Q. Are the revenues received from Rate NNS proposed to be credited to PGC Rates?

A. Yes, revenues from these rate schedules are proposed to be credited to the PGC Rates.

Q. Please describe Rate MBS (Monthly Balancing Service).

A. Rate MBS is a monthly balancing service offered by the Company that mirrors Rate MBS as offered at PNG and CPG. Service under Rate MBS allows transportation imbalances of up to 10% for the month to be carried forward in the customer's MBS account for excess deliveries of or receipt of shortfalls in subsequent months.

Q. How were the proposed MBS rates developed?

A. UGI Gas Exhibit DEL-10 provides the basis for the Rate MBS calculations, as well as the proposed MBS rates under Rates DS, LFD, and XD. These rates were developed based upon the Company's costs to provide Rate MBS service and follow the same rate design methodology utilized by CPG and PNG in their respective most recent base rate cases, updated for current costs and conditions. The proposed rates by rate class are as follows: Rate DS - $0.0050/Mcf, Rate LFD - $0.0034/Mcf, and Rate XD - $0.0031/Mcf. These rates would replace the existing rates which currently are based on the following monthly transportation volumes:

- Under 1,500 Mcf — $0.075/Mcf x Transported Volumes
- 1,500 – 20,000 Mcf — $0.035/Mcf x Transported Volumes
- 20,000 – 50,000 Mcf — $0.015/Mcf x Transported Volumes
- Over 50,000 — $0.005/Mcf x Transported Volumes

Q. Are the revenues received from Rate MBS proposed to be credited to PGC Rates?

A. Yes, revenues from these rate schedules are proposed to be credited to the PGC.

Q **Is the Company proposing to update its GPC in this proceeding?**

A. Yes. The Company is proposing to revise its GPC to reflect current labor and information technology costs associated with the procurement function. The current GPC rates is \$0.04/Mcf, the proposed GPC is \$0.0146/Mcf. Please see UGI Gas Exhibit DEL-11 for additional details on the calculation of this rate

Q **Is the Company proposing to update its MFC in this proceeding?**

A. Yes. The Company is updating the percentages for the MFCs to reflect the actual uncollectible expense for the last three years. Based on this updated data, the residential MFC will remain at 2.19%, and the MFC for the commercial class will increase slightly from 0.36% to 0.47%. Please see UGI Gas Exhibit DEL-12 for additional details.

V. <u>GET GAS PILOT PROGRAM</u>

Q. Please briefly describe the Company's GET Gas Pilot Program.

A. The Get Gas pilot is designed to help expand natural gas distribution facilities into under-served and unserved areas of the Commonwealth by permitting customers connecting to extended facilities to pay a surcharge on their rates for a defined period of time. It was approved in a Commission Order entered on February 20, 2014, at Docket No. P-2013-2356232.

Q. Did the Commission's Order approve a comprehensive settlement that was reached in this docket?

A. Yes.

Q. Did this settlement contain any provisions addressing future base rate proceedings?

A. Yes, the GET Gas settlement provides, in pertinent part:

> *In the event that any of the UGI Companies files a general base rate case during the term of the pilot, such Company will provide information, as part of its initial filing, showing how the GET Gas surcharge rates would be adjusted to reflect changes in the following items: revenue from a base rate increase, annual sales volumes, average usage per customer for GET Gas customers, depreciation rates, weighted cost of debt, return on equity, tax rates, CAP component and Uncollectibles component. Such UGI Company further agrees that if adjustments for these items would result in a decrease in GET Gas surcharge amounts, it will propose to implement such decreased surcharge rates prospectively for both new GET Gas customers and to any remaining term of the GET Gas surcharge payment for existing GET Gas customers. In the event the adjustment would suggest an increase in GET Gas surcharges, the Signatory Parties agree not to propose any prospective increase in GET Gas surcharges. In addition, and not withstanding any update of the GET Gas surcharge, the Signatory Parties agree not to oppose the UGI Companies' full and timely recovery of and a return on reasonably incurred capital investments in GET Gas facilities that are made consistent with the terms of the pilot program approved in this proceeding or any future modifications to the program approved by the Commission. Any Signatory Party shall be free to propose how such recovery shall occur, and shall be free to propose potential recovery, in part, from non-GET Gas customers.*

Q. Has the Company presented the specified information concerning potential adjustments to GET Gas Surcharge amounts?

A. Yes, this information in shown in UGI Gas Exhibit DEL-13.

Q. Does the updated information suggest a decrease in previously approved GET Gas surcharge amounts?

A. No.

Q. Is the Company proposing any adjustments to GET Gas surcharge levels?

A. No. The Company's GET Gas Pilot Program is still relatively new and, given the small number of actual projects to date, additional information needs to be gathered over time before adjustments to the approved surcharge rates should be made.

Q Has the Company included GET Gas related investment and GET Gas revenues in its base rate claim?

A. Yes. The Company has included GET Gas related investment in rate base, less deductions for depreciation and the applicable principal portion of the GET Gas surcharge. The Company is also including the annualized revenue associated with the return on investment ("ROI") portion of the GET Gas surcharge and the adder for uncollectible and CAP expenses. This amount was calculated by annualizing the projected ROI portion and adder portion of the GET Gas surcharge payments for September 30, 2017, plus the adder portion associated with those GET Gas customers who elected to pay the up-front amount of the GET Gas contribution. The total annualized amount included as revenue from the GET Gas surcharge is $198,099 and is reflected on UGI Gas Exhibit DEL-14.

VI. OTHER TARIFF MODIFICATIONS

Q. Apart from the proposed rate schedule and PGC 2 rate eliminations discussed above, has the Company proposed any other changes to its tariff in this proceeding?

A. Yes, a complete list of tariff modifications can be found in the List of Changes section in UGI Gas Exhibit F – Proposed Tariff. As noted earlier in my testimony, the primary intent of the proposed changes to the UGI Gas tariff is to standardize and harmonize, where applicable, its tariff provisions with those contained in the CPG and PNG tariffs, reflect best practices, add clarify, as well as update the UGI tariff to reflect certain proposed changes to the Company's business practices. Some of the more significant changes to the current UGI Gas Tariff No. 5 are:

- **Section 3 Guarantee of Payment.** This section has been modified to align it, where applicable, with the CPG and PNG tariffs including language changes regarding minimum deposit requirements for non-residential customers.
- **Section 5 Extension Regulation.** The Extension Regulation tariff section has been modified to align it, where applicable, with the current CPG and PNG Extension Regulation tariff sections, update the methodology used to determine allowable extension investments, and clarify language regarding cost estimates, restoration obligations and daily metering obligations.
- **Section 8 Meter Reading.** This section was updated to align it, where applicable, with the PNG and CPG tariffs except for the Heating Value Correction, which will not be included in the UGI Gas proposed Tariff No. 6.
- **Section 9 Billing and Payment.** The Company is proposing to eliminate several tariff charges as part of the effort of standardizing the tariff provisions of UGI Gas, PNG and CPG. The revenues associated with these charges have been removed from the FPFTY. The CPG tariff does not contain these charges and although the PNG tariff contains some of these charges, it is the Company's intent to eliminate them in PNG's next rate case. The charges being eliminated include:
  Payment to Collector Charge, Bill History Charge, Landlord If Shut Off (LIFSO) Charge, Turn On Charge, Shut Off Charge, Set Meter Charge, and Change of Customer Charge. Additionally, the Company is proposing to increase Returned Check Fee from $20 to $35

- **Section 11 Termination or Discontinuance of Service.** This section was updated to align it, where applicable, with the CPG and PNG tariffs and to update the Reconnection Charge to $73.00, which is equivalent to the current ½ hour charge contained in the UGI Gas Tariff No. 5 and is the charge that the Company currently is applying for reconnections.
- **Section 13 1307(f) Purchased Gas Cost.** This section was updated to align it, where applicable, with the CPG and PNG tariffs, including the elimination of PGC(2), PGC credits related to transportation customer capacity releases or assignments, and the elimination of the IRC. The Company's tariff currently provides for a credit to PGC equal to the margin realized from interruptible transportation customers utilizing pipeline capacity reflected in rates established under 1307(f). This mechanism was established in October 2000, when the restructuring occurred and Choice was implemented in Pennsylvania. The Company is proposing the elimination of the Interruptible Revenue Credit ("IRC") to reflect the results of its cost of service methodology for the interruptible group, and to simplify the administration of tariffed rates for the interruptible rate schedule.
- **Section 17 General Terms for Delivery Service for Rates DS, LFD, CDS, XD And The Delivery Service Option Of IS and IL.** This section has been modified to update it for current conditions and align it, where applicable, with the current CPG and PNG General Terms for Delivery Service tariff sections. This includes: the addition of clarifying language to address a number of balancing provisions, updates and modifications to remedy language related to default or misuse of

balancing provisions, the elimination of Information Service Fees and Pooling Fees, and the modification of Supply Transfer fees that are applied on a transactional basis rather than volumetric basis.

- **Elimination of the System Access Fee From Applicable Transportation Rate Schedules.** Due to the changes in FERC rules related to capacity releases, UGI Gas is proposing to eliminate the System Access Fee. When the System Access Fee was originally adopted in 1995, FERC rules capped the rate at which capacity could be released. The System Access Fee represented the difference between the Company's weighted average cost of demand ("WACOD") and the maximum rate at which the capacity could be released, and the System Access Fee was charged to those applicable transportation rate schedules to ensure PGC customers were not a higher cost of capacity than the applicable transportation customers. FERC rules have now changed, and the Company is able to and will release capacity at its WACOD, which eliminates the need for the System Access Fee.
- **Elimination of the Total Space Conditioning ("TSC") option for Rate Schedules R & N.** TSC is available only to customers who (1) utilize natural gas as the primary energy source for space conditioning requirements – heating and cooling, (2) utilize natural gas for water heating purposes, and (3) maintain one or more additional gas appliances (range, dryer, cooktop or oven). There are relatively few customers who are receiving the discount (103 residential customers and 10 commercial customers), and the total annual discount for all applicable customers in fiscal year 2015 was only $2,039. In addition, the PNG and CPG tariffs contain no comparable rate option. Given the minimal financial impact of the TSC option

and as part of the simplification and standardization of tariffs and rate schedules, UGI Gas is proposing to eliminate the TSC option.

- **Elimination of the Standby Charge for Rate Schedules R, RT.N and NT.** The Standby Charge applies to any customer receiving service under Rates R, RT, N, or NT who utilizes natural gas as a backup, auxiliary or temporary fuel. Given the relative popularity of natural gas as a heating fuel, the vast majority of customers who use natural gas for heating do so as their primary heating fuel. So, there are very few customers utilizing natural gas as a backup fuel. As part of the simplification and standardization of tariffs and rate schedules, the Company is proposing to eliminate the Standby Charge from all applicable rate schedules. Although the CPG and PNG tariffs currently contain provisions for a standby charge, it is the Company's intent to eliminate those provisions in future base rate proceedings.
- **Elimination of Minimum Bills for Rate Schedules N & NT.** The minimum bill provision under Rates N and NT establish a minimum bill based on 3% of the average monthly use during January, February and March billing periods, regardless of actual usage. The Company is proposing to eliminate this provision to minimize customer confusion as well as standardize tariff provisions among UGI Gas, PNG and CPG to facilitate tariff administration, as the PNG and CPG tariffs do not contain a similar minimum bill provisions.
- **Modification of Rate Schedule GL.** As part of the simplification and standardization of tariffs and rate schedules, UGI Gas is proposing to modify its current gas light rate, Rate GL, to standardize it with the current CPG gas light rate.

This includes the elimination of the optional monthly maintenance charge by UGI Gas. Currently, there are no customers that have selected the optional monthly maintenance option.

Q. Is the Company proposing any changes to its Choice Supplier Tariff?

A. Yes. The proposed changes to the Company's Choice Supplier Tariff have been incorporated into the *pro forma* tariff, Tariff No. 6, as Tariff No. 6-S. See UGI Gas Exhibit F. The proposed modifications to the Choice Supplier Tariff are summarized below.

- **Section 4 Choice Supplier Obligations.** As noted earlier, the Company is proposing to update its MFC percentages to reflect the most recent update of its uncollectible expense as a percent of revenue. As a result, the Company is also proposing to update its discount on the purchase of receivables ("POR") in conjunction with its POR Program. The uncollectible component of the residential POR discount will remain at 2.19%, and the uncollectible component of the commercial POR discount will increase slightly from 0.36% to 0.47%. The Company is proposing no change to its administrative adder for the POR Program in this proceeding, and it will remain at 0.14%. As a result, for purchased receivables, the Company shall pay participating Choice Suppliers an amount equal to 97.67% for residential amounts billed (inclusive of associated taxes) and 99.39% for non-residential amounts billed (also inclusive of taxes).
- **Section 8 Financial Security.** The reference to Call Options has been eliminated primarily because it has never been used as a financial security alternative. The Security Agreement required for suppliers who wish to utilize receivables

associated with the Company's POR Program as a partial offset to their security requirements to operate as Choice Suppliers on the Company's system has also been removed from the tariff, but will still be available as an option for Choice Suppliers.

- **Section 9 Enrollment of Customers into Rate Schedules RT and NT.** The number of days the customer has to respond to the letter of confirmation it receives from the Company was updated from 10 days to 5 days to reflect current regulations and current Company practice. Language on multiple enrollments that was not consistent with current regulations was removed.
- **Rate AG.** The Company proposes to eliminate the difference in the calculation of balancing fees between Choice Suppliers using UGI Gas capacity and Choice Suppliers using third party capacity because it is no longer applicable. The time frame for billing rate information submission was changed from 10 days to 15 days. Redundant definition language was also removed.
- **Aggregation Agreement (Pro Forma).** Redundant definitions found elsewhere in the tariff were removed. Contact information for notices and correspondence was updated. Selected sections of the Aggregation Agreement that were no longer relevant were removed.

Q. **Does this conclude your testimony?**

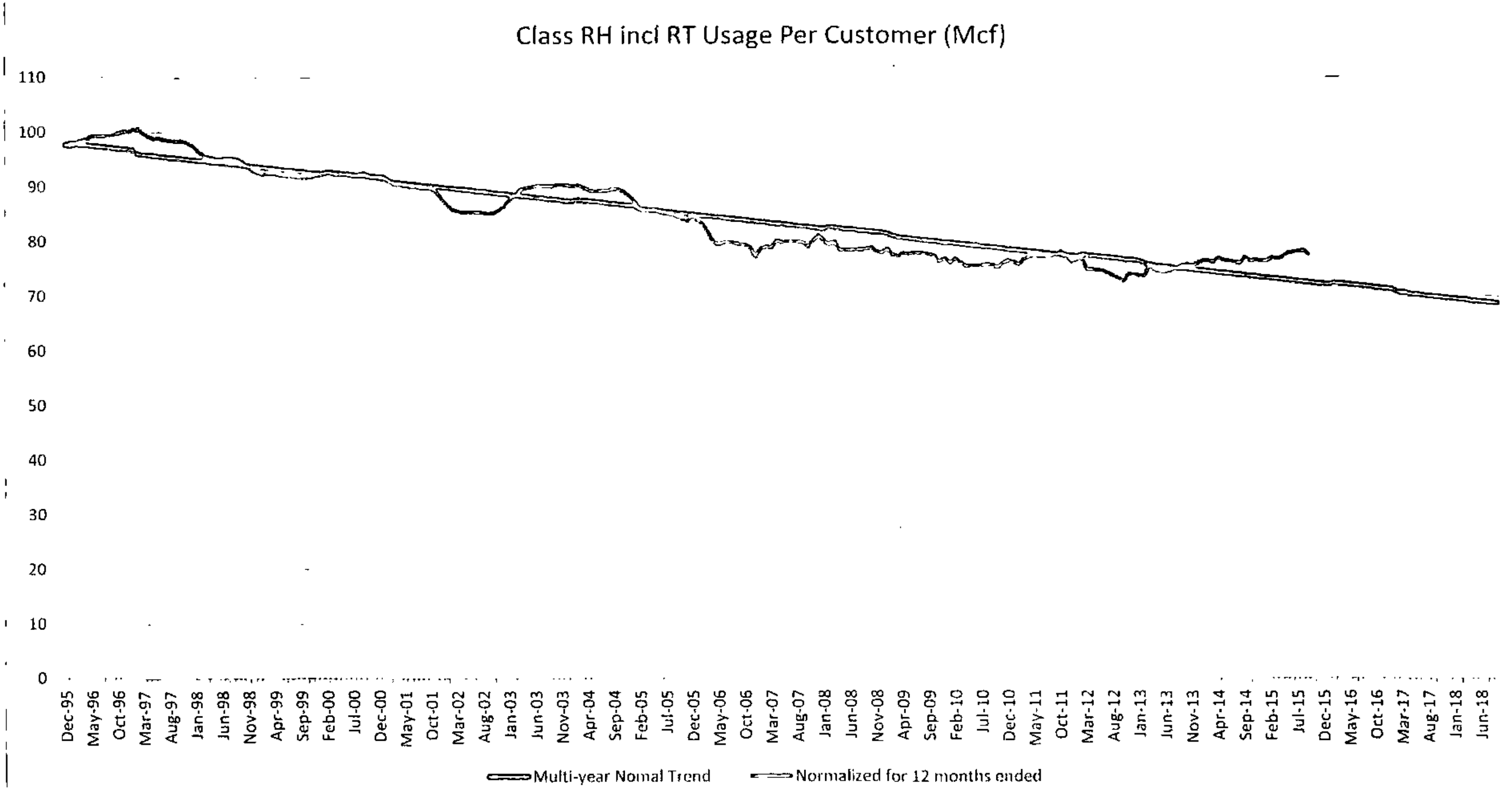
A. Yes.

UGI GAS EXHIBIT DEL-1

UGI Utilities, Inc. Primary System
15 Year Normal Heating Degree Days (2000-2014)
Gas Day Basis - Composite Average of Allentown, Harrisburg, Lancaster, and Reading)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	15 Year Average
Jan	1,104	1,086	875	1,223	1,284	1,145	844	938	1,000	1,225	1,082	1,192	951	1,001	1,267	1,081
Feb	875	864	764	1,038	912	885	891	1,117	915	880	965	893	759	924	1,064	916
Mar	561	827	675	743	677	854	691	755	737	735	557	757	451	819	908	716
Apr	401	386	364	430	388	328	333	495	335	388	288	354	373	383	430	378
May	114	121	187	208	67	221	138	110	226	140	119	92	51	158	126	139
Jun	27	12	10	53	28	7	18	12	7	25	7	2	21	4	4	16
Jul	2	3	0	0	0	0	0	4	0	0	0	0	0	0	2	1
Aug	9	0	3	0	9	0	1	16	4	6	0	2	0	2	2	4
Sep	136	105	35	42	34	25	84	50	54	78	25	51	77	111	71	65
Oct	318	321	395	400	368	295	375	192	418	381	331	355	302	300	267	335
Nov	673	463	659	525	574	562	512	703	680	526	631	536	754	723	731	617
Dec	1,158	791	1,023	952	951	1,066	779	956	963	995	1,103	795	816	968	875	946
Totals	5,378	4,979	4,990	5,614	5,292	5,388	4,666	5,348	5,339	5,379	5,108	5,029	4,555	5,393	5,747	5,214

UGI GAS EXHIBIT DEL-2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60
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Mar-17
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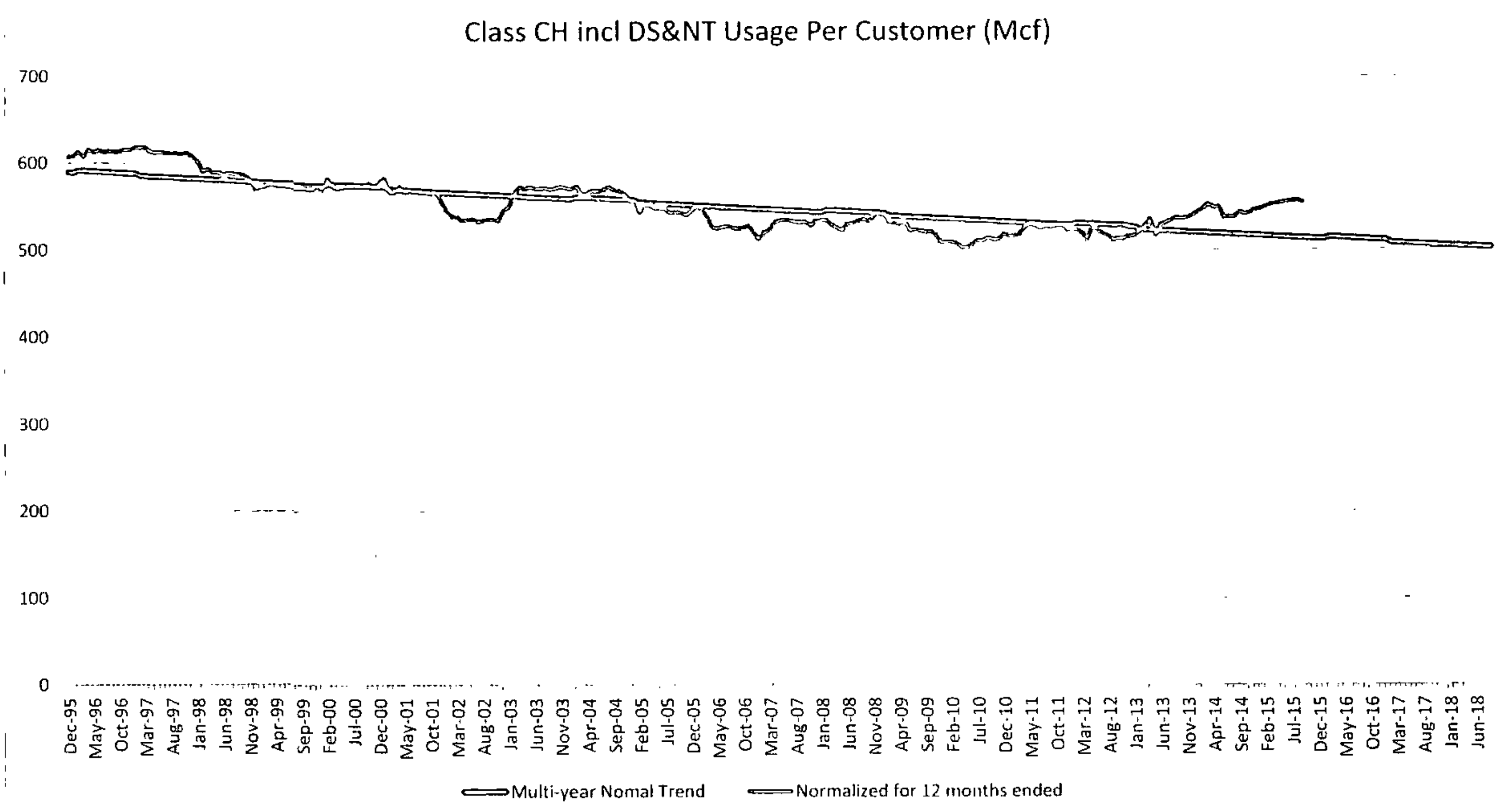
Jan-18
Jun-18
Multi-year Nomal Trend
Normalized for 12 months ended


Class CH incl DS&NT Usage Per Customer (Mcf)
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200
100
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May-96
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Jan-98
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May-16
Oct-16
Mar-17
Aug-17
Jan-18
Jun-18
Multi-year Nomal Trend
Normalized for 12 months ended

UGI GAS EXHIBIT DEL-3

Fully Projected Future Test Year 2017 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Reference
Budget 2017	127,990	398,721	
Adjustment for Customer Changes	93	761	UGI Gas Exhibit DEL-3(b)
Adjustment for Annualized Use/Customer	(4,339)	(33,064)	UGI Gas Exhibit DEL-3(c)
Adjustment for Transport Changes	(1,140)	(2,348)	UGI Gas Exhibit DEL-3(b)/(b)(1)/(c)/(c)(1)
Adjustment for PGC		(11,319)	UGI Gas Exhibit DEL-3(d)
Adjustment for MFC		(184)	UGI Gas Exhibit DEL-3(e)
Adjustment for LISHP		1,998	UGI Gas Exhibit DEL-3(f)
Adjustment for GPC		(171)	UGI Gas Exhibit DEL-3(g)
Adjustment for Interruptible		(15,721)	UGI Gas Exhibit DEL-3(h)
Adjustment for Transportation Service Revenues		(6,666)	UGI Gas Exhibit DEL-3(i)
Adjustment for Excess Take		(600)	UGI Gas Exhibit DEL-3(j)
Adjustment for STAS		1,783	UGI Gas Exhibit DEL-3(k)
Adjustment for Rate N Minimum Bill		(1,279)	UGI Gas Exhibit DEL-3(l)
Adjustment for EEC Conservation Impact	(220)	(1,484)	UGI Gas Exhibit DEL-3(m)
Adjustment for Get Gas		(238)	UGI Gas Exhibit DEL-3(n)
Fully Projected Future Test Year 2017	122,384	330,190	

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[6] Industrial-Htg	[7] NT	[8] DS	[9] Transport-Other	[10] Grand Total
1	*Total Test Year 2017 Revenues (Unadjusted)*	$ 5,539	$ 192,862	$ 15,965	$ 3,986	$ 74,182	$ 218	$ 4,408	$ 29,230	$ 20,273	$ 52,059	$ 398,721
2	PGC Revenues	(1,959)	(98,331)	9	(2,074)	(39,467)	(119)	(2,391)	-	(4,204)	(1,738)	(150,276)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 3,579	$ 94,531	$ 15,974	$ 1,912	$ 34,716	$ 99	$ 2,016	$ 29,230	$ 16,069	$ 50,320	$ 248,445
4	Average Effective Customers in Test Year 2017 (Unadjusted)	21,308	279,008	47,688	2,208	25,238	59	470	10,287	791	613	387,670
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0 168	$ 0 339	$ 0 335	$ 0 866	$ 1 376	$ 1 690	$ 4 288	$ 2 841	$ 20 310	$ 82 089	$ 0 641
6	Future Test Year 2017 Customers (Fully Adjusted)	20,447	279,985	47,688	2,167	25,410	54	459	10,287	818	604	387,919
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	(861)	977	-	(41)	172	(5)	(11)	-	27	(9)	249
8	Annualization of Margin (L 5 * L 7)	$ (145)	$ 331	$ -	$ (35)	$ 236	$ (8)	$ (48)	$ -	$ 545	$ (1,221)	$ (344)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0 260	$ 0 691	$ 0 335	$ 1 805	$ 2 939	$ 3 719	$ 9 374	$ 2 841	$ 25 624	$ 84 924	$ 1 029
10	Annualization of Total Revenue (L 7 * L 9)	$ (224)	$ 675	$ -	$ (74)	$ 505	$ (17)	$ (105)	$ -	$ 688	$ (1,221)	$ 227
11	Annualization of PGC Revenues (L 10 - L 8)	$ (79)	$ 344	$ -	$ (38)	$ 269	$ (9)	$ (57)	$ -	$ 143	$ -	$ 572
11	Total UPC (Unadjusted)-MCF	19 60	76 20	77 80	201 50	337 80	437 40	1,097 60	763 60	6,574 30		
12	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	74	-	(8)	58	(2)	(12)	-	176	(858)	(589)

Notes
Column [4] includes Com CIAC
Column [9] further detailed on CPG Exhibit PJS-4(b)(1)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total Test Year 2017 Revenues (Unadjusted)	$ 17,993	$ 12,794	$ 736	$ 20,535	$ 52,059
2	PGC Revenues	(113)	(0)	(44)	(1,581)	(1,738)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 17,880	$ 12,794	$ 692	$ 18,954	$ 50,320
4	Average Effective Customers in Test Year 2017 (Unadjusted)	261	28	21	303	613
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 68.506	$ 456.935	$ 32.961	$ 62.554	$ 82.089
6	Future Test Year 2017 Customers (Fully Adjusted)	255	27	21	301	604
7	Change in Customers during Future Test Year 2017 (L 6 - L 4)	(6)	(1)	-	(2)	(9)
8	Annualization of Margin	$ (256)	$ (954)	$ -	$ (10)	$ (1,221)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 68.940	$ 456.935	$ 35.063	$ 67.771	$ 84.924
10	Annualization of Total Revenue	$ (256)	$ (954)	$ -	$ (10)	$ (1,221)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2017 UPC (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(378)	(478)	0	(3)	(858)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Large Transp-Other	[11] Reconciliation Adj.	[12] Total
1	Total FY 17 (Unadjusted) UPC-MCF	19.80	76.20	77.80	201.50	337.80	437.40	1,097.60	763.60	6,574.30			
2	Future Test Year FY 17 UPC (Fully Adjusted)-MCF	17.80	67.30	77.50	153.70	268.30	476.80	1,182.20	766.00	5,928.80			
3	Change in UPC -MCF (L 1 - L 2)	(2.00)	(8.90)	(0.30)	(47.80)	(69.50)	39.40	84.60	2.40	(645.50)			
4	Future Test Year 2017 Customers (Fully Adjusted)	20,447	279,985	47,686	2,167	25,410	54	459	10,287	818	604		387,919
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(41)	(2,492)	(14)	(104)	(1,766)	2	39	25	(528)	60	22	(4,797)
6	Total Revenue Adjustment (L8 + L10)	$ (310)	$ (18,071)	$ (43)	$ (859)	$ (14,208)	$ 18	$ 312	$ 93	$ (1,214)	$ (295)	$ (302)	$ (34,878)
7	Total Unit Revenue Adjustment (L6/L5)	7.5744	7.2520	2.9858	8.2930	8.0451	8.2930	8.0451	3.7789	2.3000	(4.9092)		
8	Margin Adjustment (L5 *L9)	$ (135)	$ (7,440)	$ (43)	$ (417)	$ (6,673)	$ 9	$ 147	$ 93	$ (1,214)	$ (295)	$ (54)	$ (16,023)
9	Unit Margin Rate	3.3082	2.9858	2.9858	4.0268	3.7789	4.0268	3.7789	3.7789	2.3000	(4.9092)		
10	PGC Revenue (L5*L11)	$ (174)	$ (10,631)	$ -	$ (442)	$ (7,534)	$ 9	$ 166	$ -	$ -	$ -	$ (248)	$ (18,855)
11	PGC Unit Rate	4.2662	4.2662		4.2662	4.2662	4.2662	4.2662					

Notes
Column (4) includes CIAC
Column (10) further detailed on UGI Exhibit DEL-4 (c)(1)
Column (11) Adjustment reflective of interdependent relationship of sequential adjustment impacts

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ In Thousands)

Adjustment for Annualized Usage and Annualized Rates
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total FY 17 (Unadjusted) UPC-MCF					
2	Future Test Year FY 17 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF (L 1 - L 2)	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2017 Customers (Fully Adjusted)	255	27	21	301	604
5	Annualization Adjustment for Sales-MMCF	60	-	-	-	60
6	Total Revenue Adjustment	$ 39	$ (54)	$ 44	$ (323)	$ (295)
7	Unit Revenue Adjustment (L6/*L5)	0.6560	0.0000	0.0000	0.0000	(4.9092)
8	Margin Adjustment	$ 39	$ (54)	$ 44	$ (323)	$ (295)
9	Unit Margin (L8/*L5)	0.6560	0.0000	0.0000	0.0000	(4.9092)
10	PGC Revenue (L 6 - L8)	$ -	$ -	$ -	$ -	$ -

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for PGC

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Original Budget PGC 1 Rate FY 17	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Future Test Year 2017 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,445	3,089	5,201	6,415	5,308	3,919	2,093	1,012	724	635	607	726	31,174
PGC 1 Revenue Adjustment	($524)	($1,120)	($1,885)	($2,325)	($1,924)	($1,421)	($759)	($367)	($263)	($230)	($220)	($263)	($11,301)
Original Budget PGC 2 Rate FY 17	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	
Future Test Year 2017 PGC 2 Rate	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	
PGC 2 Rate Variance	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	
Total PGC 2 Volumes	2	3	2	3	0	6	1	0	1	1	1	1	19
PGC 2 Revenue Adjustment	($2)	($3)	($2)	($3)	($0)	($6)	($1)	($0)	($1)	($1)	($1)	($1)	($19)
Total PGC Revenue Adjustment	($526)	($1,123)	($1,887)	($2,328)	($1,924)	($1,426)	($760)	($367)	($263)	($231)	($221)	($264)	($11,319)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for MFC

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Orignal Budget PGC 1 Rate FY 17	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Future Test Year 2017 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,445	3,089	5,201	6,415	5,308	3,919	2,093	1,012	724	635	607	726	31,174
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	
MFC Rate N Adj Rate	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	*($0.0013)*	
Revenue Variance	($10)	($19)	($30)	($37)	($31)	($23)	($12)	($6)	($4)	($3)	($3)	($5)	($184)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for LISHP

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
Original Budget LISHP Rate FY 17	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	
Future Test Year 2017 LISHP Rate	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	
LISHP Rate Variance	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	
Total Rate R Volumes	1,426	2,639	4,142	5,059	4,277	3,216	1,741	850	472	457	450	659	25,388
Revenue Variance	$112	$208	$326	$398	$337	$253	$137	$67	$37	$36	$35	$52	$1,998

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ In Thousands)

Adjustment for GPC

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL
GPC Rate	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	*$0.0400*	
Volume Variance to Original FY17 Budget	(174)	(512)	(733)	(937)	(828)	(636)	(309)	(106)	(6)	5	6	(31)	(4,263)
Revenue Variance	($7)	($20)	($29)	($37)	($33)	($25)	($12)	($4)	($0)	$0	$0	($1)	($171)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Interruptibles to Cost of Service

Total Future Year 2017 Revenues	20,621
Adjustment to Interruptible Revenues	(14,096)
Adjustment to IRC Revenues (PGC Revenues)	(1,626)
Fully Projected Future Test Year 2017 Interruptible Revenues	4,900

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Transportation Service Revenues

	DS	LFD	DSO IS/IL	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(287)	(5)	(248)	0	0	0	(540)
System Access	(4,309)	(118)	0	0	0	0	(4,427)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
DS/PGC Credit	(1,592)	5	0	0	0	0	(1,587)
Total	(6,187)	(119)	(360)	0	0	0	(6,666)
Margin:							
Pooling	(287)	(5)	(248)	0	0	0	(540)
System Access	(1,696)	0	0	0	0	0	(1,696)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
Total	(1,983)	(5)	(360)	0	0	0	(2,348)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(100)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(600)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for STAS

	OCT 2016	NOV 2016	DEC 2016	JAN 2017	FEB 2017	MAR 2017	APR 2017	MAY 2017	JUN 2017	JUL 2017	AUG 2017	SEP 2017	TOTAL 2017
RES. G	2	3	3	3	3	3	3	2	2	2	2	2	30
H	62	106	158	191	164	126	74	43	30	29	29	37	1,049
SUBTOTAL R	64	108	161	195	167	129	77	45	32	31	31	38	1,079
RT	7	9	12	13	11	10	7	5	4	3	4	4	88
TOTAL	71	118	173	208	179	139	84	50	35	35	34	42	1,168
COM. G	2	2	2	2	2	2	2	2	1	1	1	1	22
H	13	36	70	83	66	48	27	14	16	13	12	9	407
TSC	0	0	0	0	0	0	(0)	(0)	0	0	0	0	1
SUBTOTAL C-N	15	39	73	86	68	51	29	15	17	14	13	10	429
AC	0	(0)	0	0	0	0	0	0	0	0	0	0	0
NT	9	15	24	27	23	19	11	6	3	2	2	4	145
TOTAL	24	54	97	113	90	70	40	21	20	16	15	15	574
IND. G	0	0	0	0	0	0	0	0	0	0	0	0	1
H	1	2	3	6	5	4	1	1	0	0	0	0	23
SUBTOTAL I-N	1	2	3	6	5	4	1	1	0	0	0	0	24
NT	1	2	2	3	2	2	1	1	1	0	1	1	17
TOTAL	2	4	6	9	8	6	3	1	1	1	1	1	41
GRAND TOTAL	97	176	275	329	277	214	127	72	56	52	50	58	1,783

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Rate N Minimum Bills

		Actual Fiscal Year Excess MCF's
FY10		(147)
FY11		(162)
FY12		(120)
FY13		(132)
FY14		(178)
5 YR AVG		(148)
Projected Rate N FY 17 Budget	$	8.6555
FY17 Budget Rate N Minimum Bills	$	(1,279)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for EE&C Conservation Impact

UGI EE&C Plan (Version 11/20/2015)

Yearly Gas Savings by Rate Class 2017 - 2045 (Cumulative MMBtus)

Rate Class Description	*Fiscal Year* 2017	2018	2019	2020	2021	MMBTU 5 Year Average	BTU	MCF 5 Year Average	Customers FY17 Retail Htg & Choice Htg	EE&C UPC Conservation Adj
Residential (R/RT)	11,969	52,814	176,130	281,756	360,098	176,553	1.046	168,789	323,977	(0.5)
Nonresidential (N/NT)	2,800	16,271	43,980	82,275	124,938	54,053	1.046	51,676	35,122	(1.5)
Total	***14,769***	***69,085***	***220,110***	***364,031***	***485,037***	***230,606***		***220,465***	***359,099***	

Line #	Description	[1] Residential-Htg	[2] Res Htg-RT	[3] Commercial-Htg	[4] Com Htg-NT	[5] Industrial-Htg	[6] Ind Htg-NT	[7] Total
1	Future Test Year FY 17 UPC (Fully Adjusted)-MCF	67.30	82.00	268.30	732.20	1,182.20	2,115.30	
2	Future Test Year FY 17 UPC (Fully Adjusted-Incl EE&C Impact)-MCF	66.78	81.48	266.83	730.73	1,180.73	2,113.83	
3	Change in UPC -MCF (L1-L2)	(0.5)	(0.5)	(1.5)	(1.5)	(1.5)	(1.5)	
4	End of Year Customers-Total FY 17	279,985	43,992	25,410	8,891	459	362	359,099
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(146)	(23)	(37)	(13)	(1)	(1)	(220)
6	*Total Revenue Adjustment* (L8 + L10)	*$ (1,058)*	*$ (68)*	*$ (301)*	*$ (49)*	*$ (5)*	*$ (2)*	*$ (1,484)*
7	Total Unit Revenue Adjustment (L6/L5)	7.2520	2.9858	8.0451	3.7789	8.0451	3.7789	6.7309
8	Margin Adjustment (L5 *L9)	$ (436)	$ (68)	$ (141)	$ (49)	$ (3)	$ (2)	$ (699)
9	Unit Margin Rate	2.9858	2.9858	3.7789	3.7789	3.7789	3.7789	
10	PGC Revenue (L5*L11)	$ (622)	$ -	$ (159)	$ -	$ (3)	$ -	$ (785)
11	PGC Unit Rate	4.2662		4.2662		4.2662		

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2017
($ in Thousands)

Adjustment for Get Gas Surcharge

Budget 2017	$	436
Fully Projected Future Test Year 2017	$	198
Get Gas Revenue Adjustment	$	(238)

UGI GAS EXHIBIT DEL-4

Future Test Year 2016 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	Reference
Budget 2016	125,057	388,626	
Adjustment for Customer Changes	94	770	UGI Gas Exhibit DEL-4(b)
Adjustment for Annualized Use/Customer	(3,726)	(28,261)	UGI Gas Exhibit DEL-4(c)
Adjustment for Transport Changes	331	(1,699)	UGI Gas Exhibit DEL-4(b)/(b)(1)/(c)/(c)(1)
Adjustment for PGC		(11,974)	UGI Gas Exhibit DEL-4(d)
Adjustment for MFC		(196)	UGI Gas Exhibit DEL-4(e)
Adjustment for LISHP		1,946	UGI Gas Exhibit DEL-4(f)
Adjustment for GPC		(146)	UGI Gas Exhibit DEL-4(g)
Adjustment for Interruptible		(15,857)	UGI Gas Exhibit DEL-4(h)
Adjustment for Transportation Service Revenues		(6,252)	UGI Gas Exhibit DEL-4(i)
Adjustment for Excess Take		(600)	UGI Gas Exhibit DEL-4(j)
Adjustment for STAS		1,741	UGI Gas Exhibit DEL-4(k)
Adjustment for Rate N Minimum Bill		(1,279)	UGI Gas Exhibit DEL-4(l)
Adjustment for Get Gas		100	UGI Gas Exhibit DEL-4(m)
Future Test Year 2016	121,755	326,919	

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Transport-Other	[11] Grand Total
1	Total Test Year 2016 Revenues (Unadjusted)	$ 6,038	$ 186,884	$ 15,945	$ 4,146	$ 71,332	$ 240	$ 4,488	$ 29,217	$ 18,987	$ 51,349	$ 388,626
2	PGC Revenues	(2,144)	(95,587)	9	(2,163)	(38,024)	(132)	(2,536)	-	(3,757)	(1,739)	(146,075)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 3,893	$ 91,297	$ 15,953	$ 1,983	$ 33,308	$ 109	$ 1,952	$ 29,217	$ 15,230	$ 49,609	$ 242,551
4	Average Effective Customers in Test Year 2016 (Unadjusted)	23,177	269,849	47,688	2,290	24,167	65	479	10,287	744	613	379,359
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.168	$ 0.338	$ 0.335	$ 0.866	$ 1.378	$ 1.684	$ 4.074	$ 2.840	$ 20.475	$ 80.929	$ 0.639
6	Future Test Year 2016 Customers (Fully Adjusted)	22,297	270,805	47,688	2,248	24,351	60	467	10,287	773	602	379,578
7	Change in Customers during Future Test Year 2016 (L 6 - L 4)	(880)	956	-	(42)	184	(5)	(12)	-	29	(11)	219
8	Annualization of Margin (L 5 * L 7)	$ (148)	$ 323	$ -	$ (37)	$ 254	$ (8)	$ (49)	$ -	$ 598	$ (1,267)	$ (333)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.261	$ 0.693	$ 0.334	$ 1.810	$ 2.952	$ 3.725	$ 9.367	$ 2.840	$ 25.527	$ 83.766	$ 1.024
10	Annualization of Total Revenue (L 7 * L9)	$ (229)	$ 662	$ -	$ (77)	$ 544	$ (17)	$ (114)	$ -	$ 745	$ (1,267)	$ 248
11	Annualization of PGC Revenues (L 10 - L8)	$ (81)	$ 339	$ -	$ (40)	$ 290	$ (9)	$ (64)	$ -	$ 147	$ -	$ 581
12	Total Test Year 2016 (Unadjusted)-MCF	19.60	76.20	77.80	201.50	338.50	437.40	1,138.20	763.60	6,579.40		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	73	-	(9)	62	(2)	(14)	-	192	(797)	(512)

Notes
Column [4] includes Com CIAC
Column [10] further detailed on CPG Exhibit PJS-4(b)(1)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Customer Changes
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total Test Year 2016 Revenues (Unadjusted)	$ 17,802	$ 12,243	$ 758	$ 20,546	$ 51,349
2	PGC Revenues	(114)	0	(43)	(1,582)	(1,739)
3	Revenues net of PGC - Margin (Unadjusted) (L 1 - L 2)	$ 17,688	$ 12,243	$ 714	$ 18,964	$ 49,609
4	Average Effective Customers in Test Year 2016 (Unadjusted)	261	28	21	303	613
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 67.769	$ 437.264	$ 34.002	$ 62.588	$ 80.929
6	Future Test Year 2016 Customers (Fully Adjusted)	254	26	21	301	602
7	Change in Customers during Future Test Year 2016 (L 6 - L 4)	(7)	(2)	-	(2)	(11)
8	Annualization of Margin	$ (133)	$ (1,124)	$ -	$ (10)	$ (1,267)
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 68.207	$ 437.264	$ 36.073	$ 67.808	$ 83.766
10	Annualization of Total Revenue	$ (133)	$ (1,124)	$ -	$ (10)	$ (1,267)
11	Annualization of PGC Revenues (L 10 - L8)	$ -	$ -	$ -	$ -	$ -
12	Total Future Test Year 2016 (Unadjusted)-MCF					
13	Annualization Adjustment for Sales-MMCF	(167)	(628)	-	(3)	(797)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2018
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] Residential-Non Htg	[2] Residential-Htg	[3] RT	[4] Commercial-Non Htg	[5] Commercial-Htg	[6] Industrial-Non Htg	[7] Industrial-Htg	[8] NT	[9] DS	[10] Large Transp-Other	[11] Reconciliation Adj	[12] Total
1	Total FY 16 (Unadjusted) UPC-MCF	19.80	76.20	77.80	201.50	338.50	437.40	1,138.20	763.60	6,579.40			
2	Future Test Year FY 18 UPC (Fully Adjusted)-MCF	17.70	68.70	77.50	161.30	272.90	476.80	1,182.20	766.00	5,978.80			
3	Change in UPC -MCF (L1-L2)	(2.10)	(7.50)	(0.30)	(40.20)	(65.60)	39.40	44.00	2.40	(600.60)			
4	Future Test Year 2018 Customers (Fully Adjusted)	22,297	270,805	47,688	2,248	24,351	60	467	10,287	773	602		379,578
5	Annualization Adjustment for Sales-MMCF (L3*L4)	(47)	(2,031)	(14)	(90)	(1,597)	2	21	25	(464)	1,390	17	(2,790)
6	Total Revenue Adjustment (L8 + L10)	$ (355)	$ (14,729)	$ (43)	$ (749)	$ (12,851)	$ 20	$ 165	$ 93	$ (1,068)	$ 132	$ (53)	(29,438)
7	Total Unit Revenue Adjustment (L6/L5)	7.5744	7.2520	2.9858	8.2930	8.0451	8.2930	8.0451	3.7789	2.3000	0.0951		
8	Margin Adjustment (L5 *L9)	$ (155)	$ (6,064)	$ (43)	$ (364)	$ (6,036)	$ 10	$ 78	$ 93	$ (1,068)	$ 132	$ 34	(13,384)
9	Unit Margin Rate	3.3062	2.9858	2.9858	4.0268	3.7789	4.0268	3.7789	3.7789	2.3000	0.0951		
10	PGC Revenue (L5*L11)	$ (200)	$ (8,665)	$ -	$ (386)	$ (6,815)	$ 10	$ 88	$ -	$ -	$ -	$ (87)	(16,054)
11	PGC Unit Rate	4.2662	4.2662		4.2662	4.2662	4.2662	4.2662					

Notes

Column (4) includes CIAC
Column (10) further detailed on UGI Exhibit DEL-4 (c)(1)
Column (11) Adjustment reflective of interdependent relationship of sequential adjustment impacts

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Annualized Usage and Annualized Rates
Large Transport and Interruptible Detail

Line #	Description	[1] LFD	[2] XD-F	[3] XD-I	[4] DSO IS/IL	[5] TOTAL
1	Total FY 16 (Unadjusted) UPC-MCF					
2	Future Test Year FY 16 UPC (Fully Adjusted)-MCF					
3	Change in UPC -MCF (L 1 - L 2)	0.00	0.00	0.00	0.00	0.00
4	Future Test Year 2016 Customers (Fully Adjusted)	254	26	21	301	602
5	Annualization Adjustment for Sales-MMCF	59	1,331	-	-	1,390
6	Total Revenue Adjustment	$ 38	$ 269	$ 7	$ (182)	$ 132
7	Unit Revenue Adjustment (L6/L5)	0.6560	0.2019	0.0000	0.0000	0.0951
8	Margin Adjustment	$ 38	$ 269	$ 7	$ (182)	$ 132
9	Unit Margin (L8/L5)	0.6560	0.2019	0.0000	0.0000	0.0951
10	PGC Revenue (L 6 - L8)	$ -	$ -	$ -	$ -	$ -

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for PGC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
PGC 1 Rate FY 16	$4.8547	$4.8547	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Sept 16 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.5885)	($0.5885)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,465	2,975	4,992	6,200	5,140	3,825	2,078	968	708	625	584	654	30,215
PGC 1 Revenue Adjustment	($862)	($1,751)	($1,810)	($2,247)	($1,863)	($1,386)	($753)	($351)	($257)	($227)	($212)	($237)	($11,956)
PGC 2 Rate FY 16	$4.8451	$4.8451	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	$5.0981	
Sept 16 PGC 2 Rate	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	$4.0927	
PGC 2 Rate Variance	($0.7524)	($0.7524)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	($1.0054)	
Total PGC 2 Volumes	1	3	2	3	0	6	1	0	1	1	1	1	18
PGC 2 Revenue Adjustment	($1)	($2)	($2)	($3)	($0)	($6)	($1)	($0)	($1)	($1)	($1)	($1)	($17)
Total PGC Revenue Adjustment	($863)	($1,753)	($1,812)	($2,250)	($1,863)	($1,392)	($755)	($351)	($257)	($227)	($212)	($238)	($11,974)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for MFC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
PGC 1 Rate FY 16	$4.8547	$4.8547	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	$4.6287	
Sept 16 PGC 1 Rate	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	$4.2662	
PGC 1 Rate Variance	($0.5885)	($0.5885)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	($0.3625)	
Total PGC 1 Volumes	1,465	2,975	4,992	6,200	5,140	3,825	2,078	968	708	625	584	654	30,215
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0129)	($0.0129)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	($0.0079)	
MFC Rate N Adj Rate	($0.0021)	($0.0021)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	($0.0013)	
Revenue Variance	($16)	($29)	($29)	($36)	($30)	($23)	($12)	($6)	($4)	($3)	($3)	($4)	($196)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ In Thousands)

Adjustment for LISHP

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
Original Budget LISHP Rate FY 16	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	($0.0023)	
Future Test Year 2016 LISHP Rate	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	$0.0801	
LISHP Rate Variance	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	$0.0824	
Total Rate R Volumes	1,391	2,552	4,028	4,931	4,212	3,120	1,747	816	463	450	427	589	24,725
Revenue Variance	$109	$201	$317	$388	$331	$246	$137	$64	$36	$35	$34	$46	$1,946

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for GPC

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL
GPC Rate	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	$0.0400	
Volume Variance to Original FY 16 Budget	(149)	(423)	(614)	(803)	(732)	(550)	(264)	(89)	(5)	5	6	(23)	(3,642)
Revenue Variance	($6)	($17)	($25)	($32)	($29)	($22)	($11)	($4)	($0)	$0	$0	($1)	($146)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Interruptibles to Cost of Service

Total Future Year 2016 Revenues	20,757
Adjustment to Interruptible Revenues	(14,231)
Adjustment to IRC Revenues (PGC Revenues)	(1,626)
Total Adjusted Future Test Year 2016 Interruptible Revenues	4,900

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Transportation Service Revenues

	DS	LFD	DSO IS/IL	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(270)	(5)	(248)	0	0	0	(523)
System Access	(4,063)	(156)	0	0	0	0	(4,219)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
DS/PGC Credit	(1,402)	4	0	0	0	0	(1,398)
Total	(5,735)	(157)	(360)	0	0	0	(6,252)
Margin:							
Pooling	(270)	(5)	(248)	0	0	0	(523)
System Access	(1,708)	(38)	0	0	0	0	(1,746)
Information Service	0	0	(108)	0	0	0	(108)
Supply Transfer	0	0	(4)	0	0	0	(4)
Total	(1,978)	(43)	(360)	0	0	0	(2,381)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(100)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(600)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for STAS

	OCT 2015	NOV 2015	DEC 2015	JAN 2016	FEB 2016	MAR 2016	APR 2016	MAY 2016	JUN 2016	JUL 2016	AUG 2016	SEP 2016	TOTAL 2016
RES. G	3	3	3	4	3	3	3	2	2	2	2	2	33
H	63	103	151	185	158	123	74	41	29	28	28	33	1,017
SUBTOTAL R	66	106	154	189	162	126	77	44	31	30	30	35	1,050
RT	6	10	12	13	12	9	7	5	3	3	3	4	88
TOTAL	72	116	166	202	174	136	84	48	35	34	33	39	1,138
COM. G	2	2	2	2	2	2	2	2	2	1	1	1	23
H	13	37	66	80	63	46	26	13	15	12	11	9	391
TSC	0	0	0	0	0	0	(0)	(0)	0	0	0	0	1
SUBTOTAL C-N	15	39	68	82	65	49	28	15	17	14	13	10	414
AC	0	(0)	0	0	0	0	0	0	0	0	0	0	0
NT	9	16	23	27	23	18	11	6	3	3	2	4	145
TOTAL	24	55	91	109	89	67	39	21	19	16	15	14	560
IND. G	0	0	0	0	0	0	0	0	0	0	0	0	1
H	1	2	3	6	5	4	1	1	0	0	0	0	25
SUBTOTAL I-N	1	3	3	7	6	4	2	1	0	0	0	0	26
NT	1	2	2	3	3	2	1	1	0	0	0	1	17
TOTAL	2	4	6	9	8	6	3	1	1	1	1	1	43
GRAND TOTAL	99	175	263	320	271	209	126	70	55	51	49	54	1,741

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Rate N Minimum Bills

		Actual Fiscal Year Excess MCF's
FY10		(147)
FY11		(162)
FY12		(120)
FY13		(132)
FY14		(178)
5 YR AVG		(148)
Projected Rate N FY 16 Budget	$	8.6555
FY16 Budget Rate N Minimum Bills	$	(1,279)

UGI Utilities, Inc.
Future Period- 12 Months Ended September 30, 2016
($ in Thousands)

Adjustment for Get Gas Surcharge

Budget 2016	$	108
Future Test Year 2016	$	208
Get Gas Revenue Adjustment	$	100

UGI GAS EXHIBIT DEL-5

Historic Year 2015 Sales and Revenues
Summary of Adjustments

	Sales (000's) MCF	Revenues ($000's)	
Actual 2015	128,834	448,327	
Adjustment for Customer Changes	151	1,170	UGI Gas Exhibit DEL-5(b)
Adjustment for Annualized Use/Customer	(6,954)	(49,836)	UGI Gas Exhibit DEL-5(c)
Adjustment for Transport Changes	250	252	UGI Gas Exhibit DEL-5(b)/(c)
Adjustment for PGC		(32,247)	UGI Gas Exhibit DEL-3(d)
Adjustment for MFC		(524)	UGI Gas Exhibit DEL-3(e)
Adjustment for LISHP		(498)	UGI Gas Exhibit DEL-3(f)
Adjustment for Interruptible		(16,088)	UGI Gas Exhibit DEL-3(g)
Adjustment for Transportation Service Revenues		(7,318)	UGI Gas Exhibit DEL-3(h)
Adjustment for Excess Take		(1,112)	UGI Gas Exhibit DEL-3(i)
Adjustment for Rate N Minimum Bill		(1,517)	UGI Gas Exhibit DEL-3(j)
Historic Year 2015	122,280	340,610	

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Customer Changes

Line #	Description	[1] (Incl RT) Residential-Non Htg	[2] (Incl RT) Residential-Htg	[3] (Incl NT) Commercial-Non Htg	[4] (Incl NT) Commercial-Htg	[5] (Incl NT) Industrial-Non Htg	[6] (Incl NT) Industrial-Htg	[7] DS	[8] Transport-Other	[9] Total
1	Total Historic Year Revenues	$ 7,893	$ 238,970	$ 6,970	$ 113,017	$ 549	$ 8,888	$ 19,927	$ 52,115	$ 448,327
2	PGC Revenues	(2,992)	(129,617)	(2,832)	(52,831)	(208)	(3,978)	(3,790)	(3,040)	(199,287)
3	Revenues net of PGC - Margin (L 1 - L 2)	$ 4,901	$ 109,353	$ 4,138	$ 60,186	$ 341	$ 4,910	$ 16,137	$ 49,074	$ 249,041
4	Average Effective Customers in Historic Year	28,835	304,799	3,359	32,135	114	857	702	608	371,409
5	Average Annual Margin Per Customer (L 3 / L 4)	$ 0.170	$ 0.359	$ 1.232	$ 1.873	$ 2.989	$ 5.731	$ 22.982	$ 80.665	$ 0.671
6	Number of Customers at End of Year	28,031	305,598	3,352	32,420	112	836	720	606	371,675
7	Change in Customers during Historic Year (L 6 - L 4)	(804)	799	(7)	285	(2)	(21)	18	(2)	266
8	Annualization of Margin (L 5 * L 7)	$ (137)	$ 287	$ (9)	$ 535	$ (6)	$ (119)	$ 410	$ (240)	$ 721
9	Average Annual Revenue Per Customer (L 1 / L 4)	$ 0.274	$ 0.784	$ 2.075	$ 3.517	$ 4.811	$ 10.373	$ 28.379	$ 85.662	$ 1.207
10	Annualization of Total Revenue (L 7 * L9)	$ (220)	$ 626	$ (14)	$ 1,004	$ (10)	$ (216)	$ 506	$ (240)	$ 1,436
11	Annualization of PGC Revenues (L 10 - L8)	$ (83)	$ 340	$ (6)	$ 469	$ (4)	$ (97)	$ 96	$ -	$ 716
12	Total Actual (Unadjusted)-MCF	21.10	84.30	310.20	489.80	844.50	1,710.80	7,172.00		
13	Annualization Adjustment for Sales-MMCF (L12 * L7)	(17)	67	(2)	140	(2)	(36)	128	(5)	274

Notes:
Column [1] and [3] includes GL
Column [3] includes CIAC

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Annualized Use/Customer

Line #	Description	[1] (Incl RT) Residential-Non Htg	[2] (Incl RT) Residential-Htg	[3] (Incl NT) Commercial-Non Htg	[4] (Incl NT) Commercial-Htg	[5] (Incl NT) Industrial-Non Htg	[6] (Incl NT) Industrial-Htg	[7] DS	[8] Large Transp-Other	[9] Total
1	Total FY 15 Actual UPC-MCF	21.10	84.30	310 20	489 80	844.50	1,710.80	7,172.00		
2	Fully Adjusted FY 15 UPC-MCF	18.70	72.30	280.60	408.20	820.20	1,145.60	6,568.90		
3	Change in UPC -MCF (L 1 - L 2)	(2.40)	(12.00)	(29.60)	(81 60)	(24.30)	(565.20)	(603.10)		
4	End of Year Customers-Total FY 15	28,031	305,598	3,352	32,420	112	836	720	606	371,675
5	End of Year Customers-PGC Only FY 15	24,383	262,059	2,354	23,457	70	467	-	-	312,790
6	Annualization Adjustment for Sales-MMCF (L3*L4)	(67)	(3,667)	(99)	(2,645)	(3)	(473)	(434)	561	(6,828)
7	Total Revenue Adjustment (L9 + L11)	$ (507)	$ (26,216)	$ (738)	$ (19,289)	$ (19)	$ (3,067)	$ (999)	$ 985	$ (49,850)
8	Total Unit Revenue Adjustment (L7/L6)	7.53	7.15	7.44	7.29	7.06	6 49	2.30	1.76	
9	Margin Adjustment (L6 *L10)	$ (223)	$ (10,949)	$ (400)	$ (8,997)	$ (11)	$ (1,786)	$ (999)	$ 985	$ (23,379)
10	Unit Margin Rate	3.3082	2.9858	4 0268	3.7789	4 0268	3.7789	2.30	1.76	
11	PGC Revenue (L 5/ L4)*L6*L12	$ (284)	$ (15,267)	$ (338)	$ (9,292)	$ (8)	$ (1,281)	$ -	$ -	$ (26,471)
12	PGC Unit Rate	4.8547	4.8547	4 8547	4.8547	4 8547	4 8547			

Notes:
Column (1) & (3) includes GL
Column (3) includes CIAC

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for PGC

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
PGC 1 Rate FY 15	$6.4350	$6.4350	$5.9394	$5.9394	$5.9394	$5.5663	$5.5663	$5.5663	$4.8547	$4.8547	$4.8547	$4.8547	
Sept 15 PGC 1 Rate	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	
PGC 1 Rate Variance	($1.5803)	($1.5803)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 1 Volumes	1,074	3,698	4,466	6,725	6,817	4,635	1,864	733	737	563	571	676	32,559
PGC 1 Revenue Adjustment	($1,697)	($5,844)	($4,844)	($7,295)	($7,394)	($3,299)	($1,326)	($522)	$0	$0	$0	$0	($32,220)
PGC 2 Rate FY 15	$6.1379	$6.1379	$5.9298	$5.9298	$5.9298	$5.5567	$5.5567	$5.5567	$4.8451	$4.8451	$4.8451	$4.8451	
Sept 15 PGC 2 Rate	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	$4.8451	
PGC 2 Rate Variance	($1.2928)	($1.2928)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 2 Volumes	2	2	4	5	5	4	2	1	1	1	1	1	31
PGC 2 Revenue Adjustment	($3)	($3)	($4)	($5)	($5)	($3)	($2)	($1)	$0	$0	$0	$0	($27)
Total PGC Revenue Adjustment	($1,700)	($5,847)	($4,848)	($7,300)	($7,400)	($3,301)	($1,328)	($523)	$0	$0	$0	$0	($32,247)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for MFC

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
PGC 1 Rate FY 15	$6.4350	$6.4350	$5.9394	$5.9394	$5.9394	$5.5663	$5.5663	$5.5663	$4.8547	$4.8547	$4.8547	$4.8547	
Sept 15 PGC 1 Rate	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	$4.8547	
PGC 1 Rate Variance	($1.5803)	($1.5803)	($1.0847)	($1.0847)	($1.0847)	($0.7116)	($0.7116)	($0.7116)	$0.0000	$0.0000	$0.0000	$0.0000	
Total PGC 1 Volumes	1,074	3,698	4,466	6,725	6,817	4,635	1,864	733	737	563	571	676	32,559
Rate R %	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	2.19%	
Rate N %	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	0.36%	
MFC Rate R Adj Rate	($0.0346)	($0.0346)	($0.0238)	($0.0238)	($0.0238)	($0.0156)	($0.0156)	($0.0156)	$0.0000	$0.0000	$0.0000	$0.0000	
MFC Rate N Adj Rate	($0.0057)	($0.0057)	($0.0039)	($0.0039)	($0.0039)	($0.0026)	($0.0026)	($0.0026)	$0.0000	$0.0000	$0.0000	$0.0000	
Revenue Variance	($28)	($98)	($78)	($118)	($118)	($54)	($22)	($8)	$0	$0	$0	$0	($524)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ In Thousands)

Adjustment for LISHP

	OCT 2014	NOV 2014	DEC 2014	JAN 2015	FEB 2015	MAR 2015	APR 2015	MAY 2015	JUN 2015	JUL 2015	AUG 2015	SEP 2015	TOTAL
LISHP Rate FY 15	$0.0580	$0.0580	$0.0173	$0.0173	$0.0173	$0.0098	$0.0098	$0.0098	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
Sept 15 LISHP Rate	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	($0.0024)	
LISHP Rate Variance	($0.0604)	($0.0604)	($0.0197)	($0.0197)	($0.0197)	($0.0122)	($0.0122)	($0.0122)	$0.0000	$0.0000	$0.0000	$0.0000	
Total Rate R Volumes excl CAP	605	1,675	3,626	4,508	4,974	5,000	2,462	872	531	438	383	413	25,488
Revenue Variance	($37)	($101)	($71)	($89)	($98)	($61)	($30)	($11)	$0	$0	$0	$0	($498)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Interruptibles

	FY 15 Actual	Including: Interruptible Adjustments on UGI Gas Exhibit DEL-5 (c)&(h)
Total Historic Year Revenues	20,380	20,988
Adjustment to Interruptible Revenues		(13,800)
Adjustment to IRC Revenues (PGC Revenues)		(2,288)
Adjusted Historic Year Interruptible Revenues		4,900

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Transportation Service Revenues

	DS	LFD	DSO	CDS	XD-I	XD-F	Total
Revenue:							
Pooling	(236)	(168)	(180)	(1)	(7)	(106)	(698)
System Access	(4,593)	(710)	0	(4)	0	0	(5,307)
Information Service	(47)	(208)	(78)	(2)	(4)	(40)	(379)
Supply Transfer	(3)	(0)	(4)	0	0	(2)	(9)
DS/PGC Credit	(1,148)	10	0	0	0	212	(925)
Total	(6,027)	(1,076)	(263)	(6)	(11)	64	(7,318)
Margin:							
Pooling	(236)	(168)	(180)	(1)	(7)	(106)	(698)
System Access	(2,416)	(586)	0	(4)	0	0	(3,006)
Information Service	(47)	(208)	(78)	(2)	(4)	(40)	(379)
Supply Transfer	(3)	(0)	(4)	0	0	(2)	(9)
Total	(2,702)	(963)	(263)	(6)	(11)	(148)	(4,092)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Excess Take Revenues

Excess Take (MCF)		(185)
$/MCF	$	6.00
Excess Take Revenue/Margin	$	(1,112)

UGI Utilities, Inc.
Historic Period- 12 Months Ended September 30, 2015
($ in Thousands)

Adjustment for Rate N Minimum Bills

Excess Take Mcf;s		(206)
Average FY 15 Rate N	$	7.3489
FY15 Rate N Minimum Bills	$	(1,517)

UGI GAS EXHIBIT DEL-6

Detail for Usage per Customer by Class as shown on UGI Exhibit DEL-3(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.8**	24,143	453,888
Rate R	17.8	20,447	363,336
Rate RT	24.5	3,696	90,552

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**69.3**	323,977	22,451,606
Rate R	67.3	279,985	18,844,262
Rate RT	82.0	43,992	3,607,344

Rate RT Total	77.5	47,688	3,697,896

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**307.9**	3,172	976,659
Rate N	153.7	2,167	333,127
Rate NT	549.6	990	544,104
Rate DS	6628.5	15	99,428

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**503.6**	34,975	17,613,410
Rate N	268.3	25,410	6,816,241
Rate NT	732.2	8,891	6,509,990
Rate DS	6360.8	674	4,287,179

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1584.3**	125	198,038
Rate N	476.8	54	25,747
Rate NT	1369.4	44	60,254
Rate DS	4149.5	27	112,037

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1797.9**	923	1,659,462
Rate N	1182.2	459	542,630
Rate NT	2115.3	362	765,739
Rate DS	3442.1	102	351,093

Rate NT Total	766.0	10,287	7,880,086
Rate DS Total	5928.8	818	4,849,737

Detail for Usage per Customer by Class as shown on UGI Exhibit DEL-4(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.7**	25,993	486,069
Rate R	17.7	22,297	395,517
Rate RT	24.5	3,696	90,552

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**70.6**	314,797	22,224,668
Rate R	68.7	270,805	18,617,324
Rate RT	82.0	43,992	3,607,344

Rate RT Total	77.5	47,688	3,697,896

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**305.4**	3,251	992,855
Rate N	161.3	2,248	362,581
Rate NT	549.6	990	544,104
Rate DS	6628.5	13	86,171

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**507.4**	33,876	17,188,682
Rate N	272.9	24,351	6,645,945
Rate NT	732.2	8,891	6,509,990
Rate DS	6360.8	634	4,032,747

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1644.5**	129	212,141
Rate N	476.8	60	28,608
Rate NT	1369.4	44	60,254
Rate DS	4931.2	25	123,279

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1825.0**	930	1,697,250
Rate N	1182.2	467	552,087
Rate NT	2115.3	362	765,739
Rate DS	3756.7	101	379,424

Rate NT Total	766.0	10,287	7,880,086
Rate DS Total	5978.8	773	4,621,621

Detail for Usage per Customer by Class as shown on UGI Exhibit DEL-5(c)

Residential Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**18.7**	28,031	524,180

Residential Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**72.3**	305,598	22,094,735

Commercial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**303.2**	3,364	1,019,965
Rate N & NT	279.5	3,352	936,745
Rate DS	6935.0	12	83,220

Commercial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**513.9**	33,006	16,961,783
Rate N & NT	407.6	32,420	13,214,548
Rate DS	6394.6	586	3,747,236

Industrial Non-Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1709.4**	134	229,060
Rate N & NT	447.5	112	50,116
Rate DS	8133.8	22	178,944

Industrial Heating

	(1) UPC	(2) Fully Adj Cust	(3) Sales
Total	**1862.3**	936	1,743,113
Rate N & NT	1329.6	836	1,111,563
Rate DS	6315.5	100	631,550

Rate DS Total	**6445.8**	720	4,640,949

UGI GAS EXHIBIT DEL-7

UGI Utilities, Inc. - Gas Division
Energy Efficiency & Conservation (EEC) Rider Calculation

Program Category	R/RT	Non-Residential	Total
Customer Incentives	$ 471,396	$ 310,856	$ 782,252
Administration	$ 1,108,417	$ 339,349	$ 1,447,765
Marketing	$ 172,955	$ 209,851	$ 382,806
Inspections	$ 16,422	$ 9,262	$ 25,683
Evaluation	$ -	$ 20,000	$ 20,000
Total Expenses	$ 1,769,189	$ 889,317	$ 2,658,506
Billing Determinants (Mcf)	22,744,148	31,945,029	
Proposed EEC Rider 1/	$ 0.0778	$ 0.0278	

1/ The Non-Residential Rider will be applied to Rate Schedules N, NT, DS, and LFD

UGI GAS EXHIBIT DEL-8

UGI Gas Utilities, Inc. - Gas Division
Universal Service Program Rider (USP) Calculation

		FY 17
Shortfall	$	3,644,703
CAP Admin	$	373,693
LIURP	$	1,100,000
Hardship	$	7,260
Pre-Program Arrearage	$	1,230,949
Total Expenses	$	6,356,605
Billing Determinants (Mcf)		21,720,661
Proposed USP Rider	$	0.2927

Calculation of Annual Reconciliation Adjustment related to CAP Credits and PPA

				3 Yr Average
	2012	2013	2014	
Residential Low Income Write Offs	13.30%	11.60%	12.80%	
less Residential Write Offs	2.30%	2.20%	3.00%	
Gross Adjustment	11.00%	9.40%	9.80%	10.07%
Less Average % of Write Offs Recovered				15.80%

Total Net Adjustment	8.48%

UGI GAS EXHIBIT DEL-9

UGI Gas
Rate NNS Calculation:

Assumptions:

1. Customer deliveries are assumed at a level daily rate.
2. A $0.11/Mcf average storage trip cost for Columbia FSS is used as a proxy.
3. A $2.54/Mcf gas cost assumption is used for the calculation of fuel costs associated with the storage trip.
4. A 14.2% load reduction on weekends is assumed, based on fiscal year 2015 actual usage for DS, LFD, and XD. (Note: Weekend Reduction Factor for DS uses 2015 actual usage from UGI Penn Natural and UGI Central Penn as a proxy since the majority of UGI Gas Rate DS customers are monthly read.

Calculation:

WD = weekday use
WE = weekend use

(5 x WD + 2 x WE) / 7 = average
WE = WD x (1 – 0.142)
WD = 1.17 x WE
(5 x (1.17 x WE) + 2 x WE) / 7 = average
(7.85 x WE) / 7 = average
0.89 x average = WE

Therefore:

Imbalance = 5 x (WD – average) + 2 x (average – WE)
= (5 x WD) - (3 x average) - (2 x WE)
= 5 x (1.17 x WE) - (3 x average) – (2 x WE)
= 3.85 x WE - 3 x average
= 3.85 x (0.89 x average) – 3 x average
= 0.43 x average

Unit Cost Calculation
= [(0.43 x average)/(7 x average)] x storage trip cost
= ((0.43) x (1/7) x storage trip cost
= 0.06 x storage trip cost =
= 0.06 x $0.11/Mcf
= $0.0066/Mcf

Per Unit of Demand Calculation
= $0.0066/Mcf x 20 = $.1320/Mcfd

UGI GAS EXHIBIT DEL-10

UGI Gas Exhibit DEL-10

UGI Gas

Rate MBS Calculation:

Assumptions:

1. The average capacity charge for Columbia FSS is used as a proxy.
2. System average transportation load factor is based on 2017 Fully Projected Future Test Year usage (Rates DS, LFD, XD) divided by peak day capacity, exclusive of large power generation customers.
3. Anticipated average monthly imbalance percentage based on calculated imbalance of FY 2015 actual usage and deliveries.
4. Storage use will vary with load factor, that is, 100% load factor uses 0% storage.

Calculation:

Average capacity charge for storage: $0.3456/Dth

Average capacity charge for storage: $0.3615/Mcf
(@ 1.046 Btu/mcf)

System average transportation load factor: 52.6%

Anticipated average monthly imbalance percentage: 1.1%

Rate allocation formula by Load Factor:
[($0.3615/0.526) – ($0.3615/0.526 x Load Factor)] x 0.011

Accordingly:

Rate Schedule	Load Factor	MBS Rate
Rate DS	33.6%	$0.0050/Mcf
Rate LFD	54.4%	$0.0034/Mcf
Rate XD	58.8%	$0.0031/Mcf

UGI GAS EXHIBIT DEL-11

UGI Gas Exhibit DEL-11

UGI Utilities, Inc.

Development of the Gas Procurement Charge

Line				UGIU Total
	Labor and Benefits			
(1)	Gas Supply		$	162,743
(2)	Accounting Support		$	46,684
(3)	Internal Legal Support		$	26,552
(4)	Regulatory Support		$	52,520
(5)	Management Support		$	36,062
(6)	Total Labor and Benefits Costs	(6) = (1)+(2)+(3)+(4)+(5)	$	324,561
	Non-Labor Costs			
(7)	Outside Services- Legal Support		$	60,000
(8)	IT O&M Expenses		$	8,766
(9)	Costs to be recovered by GPC	(9) = (6)+(7)+(8)	$	393,327
(10)	Sales Volumes For rates R and N (Mcf)			26,930,349
(11)	GPC rate	(11) = (9)/(10)	$	0.0146

UGI GAS EXHIBIT DEL-12

UGI Gas Utilities, Inc. - Gas Division
Merchant Function Charge (MFC) Calculation

				Rate R/RT		Rate N/NT
Total Uncollectible Revenue Requirement	$	5,561,000				
Allocator 1/				91.86%		6.28%
Uncollectible Revenue Requirement			$	5,108,335	$	452,665
Total Proposed Revenue			$	233,347,467	$	96,316,755
MFC % 2/				2.19%		0.47%

1/ The allocator is based on a 5-year average of uncollectible expenses.

2/ The MFC will be applied to bills of customers in Rate Schedules R & N only.

UGI GAS EXHIBIT DEL-13

	UGI Gas
GET Investment Total	$5,000,000
Services Cost per Customer	$2,986
Mains Cost per Customer	$4,371
Number of Customers	680
Current Annual Forecast Residential GET Customers	673
Current Annual Forecast Commercial GET Customers	7
Residential Load per Customer	76.3
Commercial Load per Customer	292.2
Residential Base Revenues per Customer at Proposed Rates	$448
Commercial Base Revenues per Customer at Proposed Rates	$1,473
Base Rate Revenues	$311,438.09
Supported Investment	$1,990,750
GET Investment Recovery Need	$3,009,250
Residential Base Revenue Share	96.8%
Commercial Base Revenue Share	3.2%
Base Residential GET Monthly Customer Charge	$67.12
Annual Commercial GET Charge Needed	$2,648
Base Commercial GET Monthly Customer Charge	$12.85
Base Commercial GET Volumetric Charge	$8.54
Proposed Pre Tax WACC	13.96%
Depreciation Rate	1.680%
Residential Gross Up for CAP and Uncollectible Exp	$0.92
Commercial Gross Up for Uncollectible Exp	$0.67
Total Residential GET Monthly Customer Charge	$68.04
Total Commercial GET Monthly Customer Charge	$13.52
Total Commercial GET Volumetric Charge	$8.54
Proposed After Tax Weighted Average Cost of Capital	8.17%
Tax rate	41.49%

UGI GAS EXHIBIT DEL-14

GET Revenues	Sep-17	**Annulaized Amount (Sept x 12)**
ROI Component of Monthly Surcharge GET Payments (interest)	$ 14,974	$ 179,685
Uncollectible & CAP Adder Component of Monthly Surcharge GET Payments	$ 431	$ 5,167
Uncollectible & CAP Adder Component of Lump Sum Upfront GET Payments	$ 1,104	$ 13,248
Total	$ 16,508	$ 198,099